# Detailed Public Design Report
for the
# JEA Large-Scale CFB Combustion Demonstration Project

Submitted to
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Building Community

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# 1.0 OVERVIEW

JEA is the largest public power company in Florida and the eighth largest public power company in the US. JEA currently serves nearly 350,000 customers and is experiencing a load growth rate of more than 3% per year. Prior to the JEA Large-Scale CFB Demonstration Project, JEA's Northside Generating Station (NGS) consisted of three oil/gas-fired steam electric generating units. NS Units 1 and 2 were each nominally rated at 275 megawatts (MW) and Unit 3 at 518 MW. Units 1 and 3 had been in service since 1966 and 1977 respectively. Unit 2 was completed in 1972, but had been inoperable since about 1983 due to major boiler problems.

As part of its Integrated Resource Planning Study in 1996, JEA concluded that additional base load capacity was needed to support Jacksonville's growing need for energy. The optimum source for that additional capacity was repowering NS Unit 2 with a nominal 300 MW state-of-the-art atmospheric circulating fluidized bed (CFB) boiler fueled by coal and/or petroleum coke. In order to provide the project with an overall environmental benefit, increase the economies of scale, and further diversify JEA's overall fuel mix, a decision was made to repower NS Unit 1 with an identical CFB boiler as well. The environmental benefits included a reduction in emissions of nitrogen oxides, sulfur oxides and particulate matter by at least 10% compared to 1994/95 levels while increasing the net plant capacity by 250%.

In early 1997, detailed Condition Assessments of Unit 1 and Unit 2 Balance of Plant equipment and systems were conducted by JEA and Black & Veatch. The results of these assessments indicated that both Unit 1 and Unit 2 were good candidates for repowering and capable of operating for an additional twenty years, provided various equipment and system upgrades were made.

In April 1997, JEA's Authority approved the project and authorized staff to proceed with contract negotiations and environmental permitting. Contract negotiations were subsequently initiated with Foster Wheeler and the United States Department of Energy (DOE) for participation in cost sharing for the first unit (Unit 2) as a Large-Scale CFB Combustion Demonstration Project. Cooperative Agreement DE-FC21-90MC27403 between JEA and the DOE was finalized in September 1997. The Agreement provided for cost sharing based on a total estimate of $309,096,512 with 75.8% for JEA and 24.2% for DOE. This represented a DOE cost share of $74,733,833 of which JEA would receive $73,072,464 with $1,661,369 paid to an earlier potential participant for Phase 1A Preliminary Engineering.

Environmental permitting work was initiated by Foster Wheeler Environmental in the latter part of 1997. The permitting work, and associated preliminary engineering, proceeded through 1998, and early 1999. Foster Wheeler began detailed engineering for the Boiler Island, including the Air Quality Control System, Chimney, and Limestone Preparation System, in December 1998. Black & Veatch began detailed engineering for Balance of Plant systems, including the Fuel Handling System, in February 1999. Permits necessary to begin construction were issued in July 1999 with site clearing and construction beginning in August 1999.

Initial synchronization of Unit 2 occurred on February 19, 2002, and initial synchronization of Unit 1 occurred on May 29, 2002. Additional schedule information is provided in the Project Milestone Schedule in Appendix 5.

During design and construction, a number of papers were presented on the JEA Large-Scale CFB Demonstration Project at various conferences. The project received the 2002 Powerplant

Award from Power magazine and has been nominated for the Power Engineering 2003 Project of the Year Award.

The purpose of this report is to summarize the non-proprietary design information for the project as required by the Cooperative Agreement between JEA and the DOE. Although the DOE participation was only in the Unit 2 and Common Facilities portion of the project, the project execution by JEA included design and construction for repowering of Unit 1 in the same time frame. Thus, while this report is primarily for Unit 2 and Common Facilities, it also contains some summary type information for the entire Unit 1 and 2 Repowering Project. Project design activities for both units were essentially complete by July 2001, although some design changes were made during the latter stages of construction and start-up. Changes during start-up will be summarized in the Start-up Modifications Report.

# 2.0 PROJECT HISTORY

## 2.1 Background

In September 1997, the U.S. Department of Energy (DOE) and JEA entered into an agreement to repower JEA's Northside Generating Station Unit 2 with CFB boiler technology from Foster Wheeler. The purpose of this agreement was to demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility.

CFB technology is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows $SO_2$ capture via limestone injection while minimizing $NO_x$ emissions. The technology is flexible enough to handle a wide range of coals as well as petroleum coke and blends of coal and coke. CFB boilers have been installed in smaller, industrial-size plants but have only recently been considered for larger utility power plants. The DOE helped test a 110 MW CFB boiler at a power station in Colorado in one of its earliest and most successful Clean Coal Technology projects. At nearly 300 MW each, the JEA CFB boilers more than double the size of the Colorado unit and are the world's largest.

The JEA Large-Scale CFB Demonstration Project involved repowering Northside Unit 2, an existing 275 MW oil/gas fired boiler which had been out of service since the early 80's, with a 297.5 MW CFB boiler. The DOE is contributing approximately $73 million from the Clean Coal Technology Program, with JEA providing the remainder of the total budget. The DOE cost sharing includes two years of demonstration test runs, during which both coal and coal/petroleum coke blends will be fired. JEA also repowered Northside Unit 1 with an identical CFB boiler. The DOE did not cost share in the Unit 1 repowering.

Prior to the Repowering Project, Units 1 and 3 fired relatively high cost fuels; thus, capacity factor was limited. After the repower, Units 1 and Unit 2 will fire relatively low cost solid fuels, and plant power production is expected to increase to 2½ times previous levels. At the same time, total plant emissions will be 10% below previous (1994/1995) levels.

## 2.2 Project Organizational Structure

JEA contracted with Foster Wheeler to supply the extended boiler island scope of the project. Foster Wheeler Energy Corporation (FWEC) provided the design and supply of the CFB boilers. Foster Wheeler USA (FWUSA) provided engineering, procurement, and construction management services on a cost reimbursable basis for installation of the boilers and for furnishing and erecting the air pollution control systems, chimney, limestone preparation system, and ash handling systems. Foster Wheeler Environmental Corporation, a subsidiary of FWUSA, provided environmental permitting services.

The remaining portions of the project were implemented by JEA staff and supplemented by Black & Veatch Corporation through a pre-existing Alliance with JEA for engineering services. Procurement, construction and related services were provided through other pre-existing Alliances between JEA and Zachry Construction Corporation, Fluor Global Services, W.W. Gay Mechanical Contractor, Inc., and Williams Industrial Services Inc. This work included upgrades of the existing turbine island equipment, construction of the receiving and handling facilities for the fuel and reagent required for solid fuel firing, upgrading of the electrical switchyard facilities, and construction of an ash management system.

## 2.3 Project Scope

The project involved the construction and operation of two CFB boilers fueled by coal and petroleum coke to repower two existing steam turbines, each generating nearly 300 MW. CFB boilers are generally capable of removing over 98% of $SO_2$. However, to improve the overall economics and environmental performance, a polishing scrubber was included to minimize reagent consumption while firing petroleum coke containing up to 8.0% sulfur. The relatively low furnace operating temperature of about 1600° F inherently results in appreciably lower nitrogen oxide emissions compared to conventional coal-fired power plants. However, the project also included a new selective non-catalytic reduction (SNCR) system to further reduce emissions of nitrogen oxides. Over 99.8% of particulate emissions are removed by a baghouse.

In addition to the CFB combustor and the air pollution control systems, new equipment for the project included a chimney as well as fuel, limestone, and ash handling systems. The project also required overhaul and/or upgrades of existing systems such as the steam turbines, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the plant control systems.

New construction associated with the Repowering Project occupies approximately seventy-five acres of land at the Northside Generating Station (see the Site Arrangement Drawing and Overall Plot Plan in Appendix 2). Solid fuel delivery to the site required new receiving, handling, and storage facilities. Limestone and ash storage and handling facilities were also required. Wherever possible, existing facilities and infrastructure were used for the project. These include the intake and discharge system for cooling water, the wastewater treatment system, and the electric transmission lines and towers.

Project activities include engineering and design, permitting, equipment procurement, construction, start-up, and a twenty-four month demonstration of the commercial feasibility of the technology. During the two year demonstration, Unit 2 will be operated on several different types of coal and coal/petroleum coke blends, to enhance the viability of the technology. Upon completion of the demonstration program for the DOE, Unit 2 will continue in commercial operation.

# 3.0 PROJECT TECHNICAL OVERVIEW

The CFB boiler technology selected by JEA for the Demonstration Project is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows $SO_2$ capture via limestone injection, while minimizing $NO_x$ emissions. The technology provides the capability to burn a wide range of fuels including coal, petroleum coke, and blends of the two.

Although CFB boilers are generally capable of removing over 98% of $SO_2$, a polishing scrubber was included to minimize reagent consumption and improve environmental performance while firing petroleum coke containing up to 8.0% sulfur. Based on the incremental amount of $SO_2$ removal required, dry scrubber technology, followed by a baghouse for particulate removal, was selected for the Air Quality Control System (AQCS).

Firing of solid fuels on the Northside site required the design and installation of a completely new system for receiving, handling, and storing coal and petroleum coke. The same system is used for receiving and handling limestone for CFB boiler reagent.

Firing of solid fuels results in the production of ash byproducts, so new provisions had to be designed and installed for handling and processing these materials. Facilities were also included for storing the byproducts pending development of useful markets for these materials.

A detailed condition assessment of existing systems and components was conducted during the conceptual design stage of the project. Based on that report, many systems and components were reused, upgraded, or replaced.

## 3.1 CFB Technology Description

The various types of solid fuel combustion systems historically available, such as stokers, pulverized fuel, and cyclone-fired boilers have distinct and specific advantages and disadvantages. A few of the disadvantages that are common to each of them in varying degrees are:

> Low residence time of material in the combustion zone (except stokers) requires high combustion temperatures to assure adequate combustion efficiency without excessive unburned carbon losses.
>
> High temperatures, usually more than 1800° F, contribute to the formation of nitrogen oxides, which are environmentally objectionable.
>
> High combustion temperatures also dictate the use of post-combustion treatment scrubbers for removal of sulfur dioxide ($SO_2$). When the combustion temperature is maintained between 1500° and 1600° F, $SO_2$ removal can be accomplished by injecting limestone ($CaCO_3$) directly into the furnace.
>
> The low ash fusion temperature of many solid fuels prevents use with conventional combustion systems because the higher combustion temperatures result in the formation of slag on boiler heat transfer surfaces.

The need to overcome these difficulties when using low-grade, less expensive fuels has led to the development of fluidized bed combustion systems. Presently, there are two distinct types of fluidized bed boilers in commercial operation: bubbling bed and circulating bed.

### 3.1.1 Bubbling Bed

In the bubbling bed-type boiler, a layer of solid particles (mostly limestone, sand, ash and calcium sulfate) is contained on a grid near the bottom of the boiler. This layer is maintained in a turbulent state as low velocity air is forced into the bed from a plenum chamber beneath the grid. Fuel is added to this bed and combustion takes place. Normally, raw fuel in the bed does not exceed 2% of the total bed inventory. Velocity of combustion air is kept at a minimum, yet high enough to maintain turbulence in the bed. Velocity is not high enough to carry significant quantities of solid particles out of the furnace.

This turbulent mixing of air and fuel results in a residence time of up to five seconds. The combination of turbulent mixing and residence time permits bubbling bed boilers to operate at a furnace temperature below 1650° F. At this temperature, limestone is mixed with fuel in the furnace to achieve greater than 90% sulfur removal. Boiler efficiency is the percentage of total energy in the fuel that is used to produce steam. Combustion efficiency is the percentage of complete combustion of carbon in the fuel. Incomplete combustion results in the formation of carbon monoxide (CO) in the flue gas plus unburned carbon in the solid particles leaving the furnace. In a regular bubbling bed fluidized boiler, combustion efficiency can be up to 92% with the unburned carbon loss component typically in the 2% to 5% range. A good figure, but lower than that achieved by pulverized or cyclone-fired boilers. In addition, some fuels that are very low in volatile matter cannot be completely burned within the residence time in bubbling bed-type boilers.

### 3.1.2 Circulating Fluidized Bed (CFB)

The need to improve the fluidized bed combustion efficiency (which also increases overall boiler efficiency and reduces operating costs) and the desire to burn a much wider range of fuels has led to the development and application of the circulating fluidized bed (CFB) boiler. Through the years, boiler suppliers have been increasing the size of these high-efficiency steam generators. At present, Foster Wheeler has a design for the CFB process of more than 400 MW of steam-producing power. See Fig. 3-1 for a typical Foster Wheeler CFB Process Layout.

The CFB process offers the means for efficiently burning a wide variety of fuels while maintaining low emissions. Fuel is fed to the lower furnace where it is burned in an upward flow of combustion air. Fuel, ash, and unburned fuel carried out of the furnace are collected by a separator and returned to the lower furnace. Limestone, which is used as a sulfur sorbent, is also fed to the lower furnace. Furnace temperature is maintained in the range of 1500° to 1700° F by suitable heat absorbing surface. This process offers the following advantages:

**Fuel Flexibility** – The relatively low furnace temperatures are below the ash softening temperature for nearly all fuels. As a result, the furnace design is independent of ash characteristics, which allows a given furnace to handle a wide range of fuels.

**Low $SO_2$ Emissions** – Limestone is an effective sulfur sorbent in the temperature range of 1500° to 1700° F. $SO_2$ removal efficiency of 95% and higher has been demonstrated along with good sorbent utilization.

**Low $NO_X$ Emissions** – Low furnace temperatures of 1500° to 1700° F plus staging of air feed to the furnace produces very low $NO_X$ emissions.

**High Combustion Efficiency** – The long solids residence time in the furnace resulting from the collection/recirculation of solids via the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization airflow, results in high combustion efficiency, even with difficult-to-burn fuels. The unburned carbon loss component of the combustion efficiency is typically in the 1% to 2% range. For the JEA Northside boilers, the predicted unburned carbon loss is 2% on coal and 1.25% on petroleum coke.

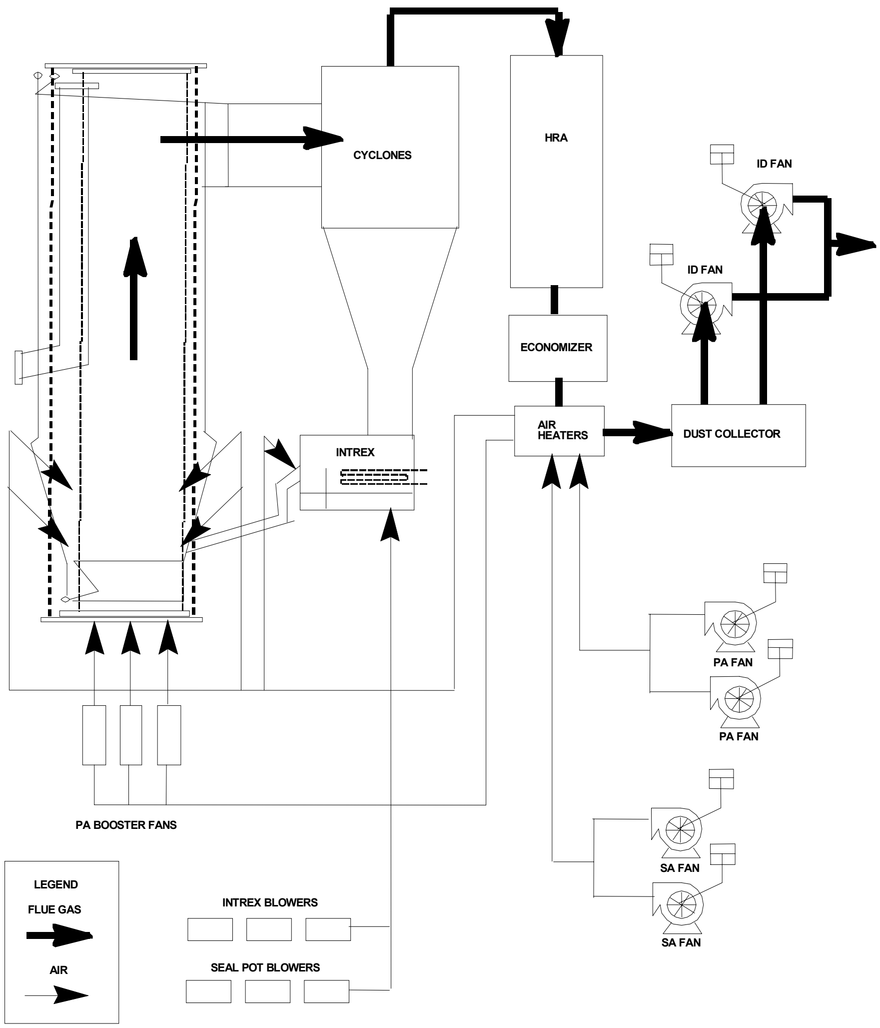


Figure 3-1 Typical Foster Wheeler CFB Process Layout

HRA = Heat Recovery Area    ID = Induced Draft
PA = Primary Air    SA = Secondary Air

## 3.2 CFB Boilers

In the furnace of a circulating fluidized bed boiler, gas velocity is increased to more than that in a bubbling bed boiler. The result of this increase in velocity causes the dense mixture of solids (fuel, limestone and ash) to be carried up through the furnace. There is a minimum gas entrainment velocity required for the particles to lift and separate (elutriate) and flow up, through and out of the furnace. Reaching this entrainment velocity marks the change from a bubbling bed-type boiler to a circulating bed-type boiler. Circulating fluidized bed systems operate in the region between that of a bubbling fluidized bed and circulating fluidized bed until approximately 500° F bed temperature is reached. When this has been accomplished, airflows are above minimum and the entrainment velocity is reached. The basic process is shown in Fig. 3-1. A top view of the Foster Wheeler CFB boiler design is shown in Fig. 3-2.

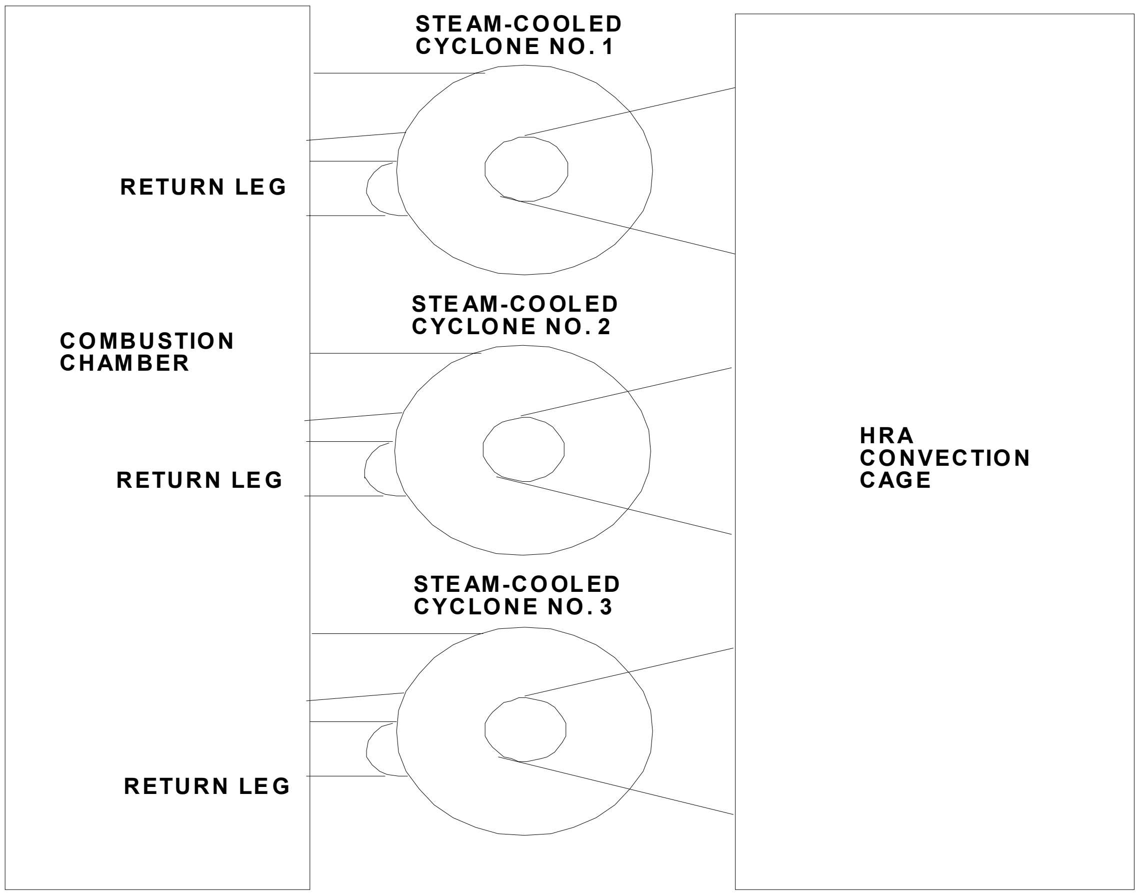


Figure 3-2 Top View of CFB Boiler

Solids move up through the furnace at lower velocities than the air and gas mixture. This fact, coupled with the elongated furnace in a CFB boiler and recirculating bed material, allows particle residence time of up to a few minutes in the furnace. During this long residence period, the crushed fuel particles are consumed in the combustion process.

The fuel is reduced in size during the combustion process and thoroughly mixed with limestone and the balance of the bed material. This action produces the "fines" (small particles of bed material) necessary to have circulating bed material in the "hot loop." Long residence time, coupled with small particle size and high turbulence, produces a better sulfur removal rate with less limestone than in a bubbling bed boiler. In addition, higher gas velocity produces heat transfer rates that are greater than in the bubbling bed.

While in normal operation, there is no defined fixed bed depth in a CFB boiler. There are different densities of circulating bed material depending on the weight of the particle. Heavy particles stay in the lower region of the furnace. As the height within the furnace increases, the smaller bed particles (less dense) enter the circulation path of the hot loop. When the particles break down enough, they are carried out of the hot loop (circulating path) with the flue gas as fly ash.

### 3.2.1 Sulfur Removal in the CFB

Most sulfur in the fuel combines chemically with oxygen during the combustion process to form sulfur dioxide ($SO_2$) or sulfur trioxide ($SO_3$). These forms of sulfur generated during the combustion process must be removed to comply with the environmental discharge limitations placed on power plants today.

The mechanism for removal of $SO_2$ with powdered limestone is:

Calcination of limestone: $CaCO_3 + \text{Heat} = CaO + CO_2$

Reaction with sulfur (sulfation): $CaO + \frac{1}{2}O_2 + SO_2 = CaSO_4$ (gypsum)

The product, $CaSO_4$, is an inert substance sometimes known as "gypsum." Limestone continuously reacts with the fuel at normal operating temperatures. Sulfation reaction requires there always be an excess of limestone. The amount of excess limestone required depends on several factors, such as the amount of sulfur in the fuel, the temperature of the bed material in the furnace and the physical and chemical characteristics of the limestone (reactivity). The ideal reaction temperature range is 1500° to 1700° F.

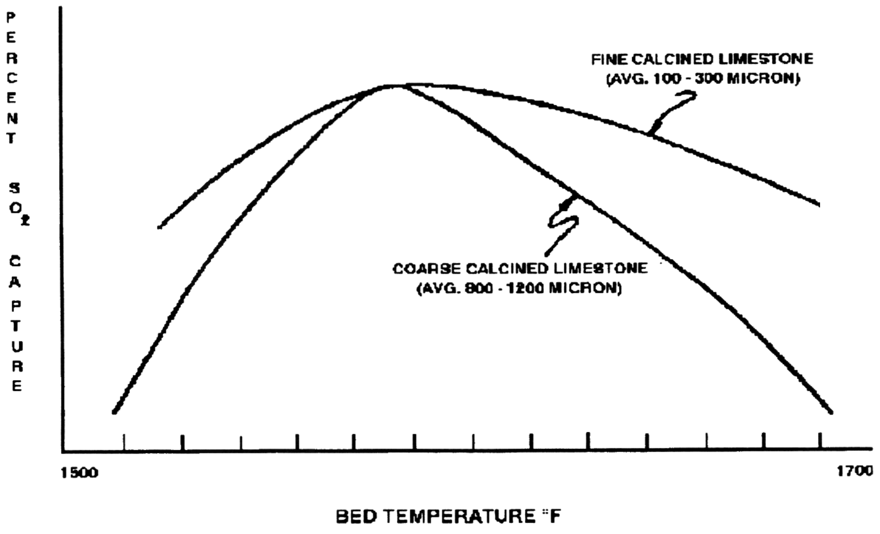


Figure 3-3 Bed Temperature vs. Sulfur Capture

There is little limestone reaction when the bed temperature is below 1500° F or above 1700° F. (See the Bed Temperature versus Sulfur Capture curve in Fig. 3-3.) More than 90% of the $SO_2$ can be removed at optimum conditions. Outside this best temperature range, significant increases in limestone feed rates (Ca/S ratio) are required to maintain emission levels within acceptable limits.

A fluidized boiler's bed material typically contains limestone products (new and old) as the predominant bed material, with smaller amounts of fuel, ash and impurities (for example, rocks or tramp iron).

About 80% of the bed is reacted (old) limestone and 10% raw (new) (CaO and $CaSO_4$); 2% to 3% of the bed is fuel, and 2% to 3% of the bed is ash. Calcium oxide content rises with decreasing fuel sulfur content and high removal rates. The ash content increases with higher ash fuels and those that are less friable.

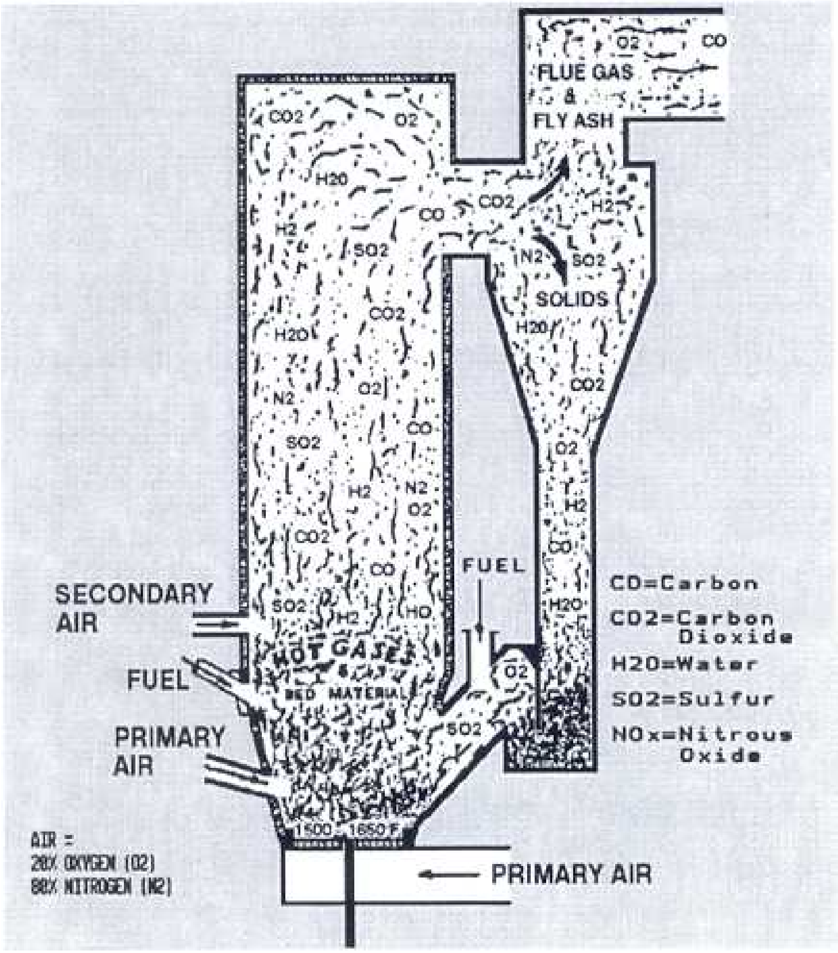


Figure 3-4 Boiler Hot Loop

Fresh limestone enters the furnace and, aided by the normal operating temperatures, calcines by liberating $CO_2$. It then absorbs $SO_2$ from the burning fuel that sulfates the limestone, converting limestone to gypsum. During the calcining stage, limestone is physically weak and is easily decrepitated (crumbled) into dust and carried out of the bed (elutriated) by the furnace draft.

With a sulfur content in the fuel of 2.5% or more, enough $SO_2$ is produced during combustion that the limestone can readily sulfate (combine with the $SO_2$). This strengthens the limestone and reduces loss of limestone from decrepitation and elutriation (limestone attrition). A low sulfur content can lead to loss of limestone through attrition. This loss must be compensated for by increasing limestone feed to maintain bed inventory and $SO_2$ capture. Reacted limestone or used limestone ($CaSO_4$) and some excess limestone is carried out of the CFB furnace and trapped by the downstream flue gas cleanup equipment.

### 3.2.2 Advantages of CFB Boilers

Combustion efficiency is improved in the CFB boiler compared to a bubbling bed boiler. This is primarily because the elutriated particles are separated from the flue gas in cyclone collectors (hot cyclones and vortex finders) and returned to the furnace for further exposure to combustion temperature and high turbulence. This fact results in an increase of up to 4% in overall combustion efficiency. These particles are the circulating bed material within the "hot loop." The hot loop is a term given for the circulating path of bed material inside the boiler.

Other advantages of CFB boilers are:

- Can burn a wide range of low-grade or high-grade fuels
- Better sulfur capture with less limestone and low $SO_2$ emissions
- Lower operating temperatures, compared to other types of boilers, reduce the chance of slag and excess stack emissions
- Improved heat transfer with the increase in residence time for fuel and limestone Lower $NO_x$ emissions because of low operating temperatures, less than 1700° F

Lower operating temperatures mean fewer pollutants and less equipment needed to clean up the combustion process while burning a variety of fuels. The ratios between operating gas velocity and minimum solids entrainment velocity allow turndown ratios as high as four to one. Operation over a wide range of boiler loads is possible without starting and stopping burners and auxiliary equipment.

### 3.2.3 Northside CFB Boiler

The design parameters at maximum continuous rating (MCR) for the Northside CFB Boilers are as follows:

| Parameter | 100% MCR |
|---|---|
| Main Steam Flow | |
| Main Steam Pressure at Superheater Outlet Header | |
| Main Steam Pressure at Turbine | |
| Main Steam Temperature | |
| Reheat Steam Flow | |
| Reheat Steam Pressure | |
| Reheat Steam Temperature | |
| Boiler Efficiency firing Performance Coal | |
| Boiler Efficiency firing Performance Petroleum Coke | |

The performance fuel specifications for coal and petroleum coke, including ranges, are indicated in the following table.

Boiler Process and Instrument Diagrams are included in Appendix 1. Boiler Arrangement Drawings are included in Appendix 3.

Table 3-1 Fuel Specifications

| **Delayed Petroleum Coke** | | | | Performance Range | |
|---|---|---|---|---|---|
| | Minimum | Maximum | Performance | Minimum | Maximum |
| Heat Content, Btu/lb (HHV) | 13,000 | na | 14,000 | 13,900 | na |
| Hardgrove Grindability | 25 | 80 | wr | wr | wr |
| As received Particle Size (inches) | 0 | 4 | na | na | na |
| | | | | | |
| Proximate Analysis | | | | | |
| | | | | | |
| Volatile Matter | 7.0 | 14.0 | 9.0 | 7.0 | 11.0 |
| Fixed Carbon | 71.0 | 88.0 | 81.6 | na | na |
| Moisture | na | 15.0 (Note 7) | 9.0 | na | 15.0 |
| Ash | na | 3.0 | 0.4 | na | 3.0 |
| | | | | | |
| Ultimate Analysis | | | | | |
| | | | | | |
| Carbon | 78.0 | 89.0 | 79.0 | 79.0 | 85.0 |
| Hydrogen17 | 3.2 | 5.8 | 3.6 | 3.25 | 4.17 |
| Nitrogen | 0.4 | 2.0 | 1.0 | .73 | 1.6 |
| Oxygen | 0.1 | 1.8 | 0.3 | 0.3 | 1.65 |
| Sulfur | 3.0 | 8.0 | 6.7 | 4.0 | 8.0 |
| Moisture | na | 15.0 (Note 7) | 9.0 | na | 15.0 |
| Ash | na | 3.0 | 0.4 | na | 3.0 |
| Vanadium, ppm | na | 3,500 (Note 8) | na | na | na |
| Nickel, ppm | na | 600 (Note 8) | na | na | na |
| Fluoride | na | (Note 5) | na | na | na |
| Lead | na | (Note 5) | na | na | na |
| Mercury | na | (Note 5) | na | na | na |
| Chlorine | na | (Note 10) | na | na | na |
| Alkalis | na | (Note 9) | na | na | na |

| **Coal** | Performance | | | Performance Range | |
|---|---|---|---|---|---|
| | (Note 11) | | | Minimum | Maximum |
| Heat Content, Btu/lb (HHV) | 12,690 | | | 11,600 | 13,959 |
| Hardgrove Grindability | na | | | na | na |
| As received Particle Size (inches) | na | | | na | na |
| Ash Fusion (reducing, soft, °F) | na | | | na | na |
| Volatile Matter (% DAF) | 43.41 | | | 39.1 | 47.0 |
| | | | | | |
| Proximate Analysis | | | | | |
| Volatile Matter | 35.63 | | | na | (Note 4) |
| Fixed Carbon | 46.4 | | | na | na |
| Moisture | 5.2 (Note 8) | | | na | 12.0 |
| Ash (Note 3) | 12.8 | | | 7.0 | 15.0 |
| | | | | | |
| | | | | | |

| | | | | |
|---|---|---|---|---|
| **Coal (continued)** | Performance | | Performance Range | |
| | (Note 11) | | Minimum | Maximum |
| Ultimate Analysis | | | | |
| Carbon | 68.6 | | 66.6 | 70.6 |
| Hydrogen | 4.6 | | 4.0 | 5.2 |
| Nitrogen | 1.3 | | 0.8 | 1.6 |
| Oxygen | 4.11 | | 3.98 | 4.2 |
| Chlorine | 0.09 | | na | 0.1 |
| Sulfur (Note 3) | 3.3 | | 2.97 | 3.6 |
| Moisture | 5.2 (Note 7) | | na | 12.0 |
| Ash (Note 3) | 12.8 | | 7.0 | 15.0 |
| Fluoride | na | | na | na |
| Lead | na | | na | na |
| Mercury | na | | na | na |
| | | | | |
| Mineral Analysis of Coal Ash | | | | |
| Phosphorous Pentoxide | wr | | wr | wr |
| Silicon Oxide | wr | | wr | wr |
| Ferric Oxide | wr | | wr | wr |
| Aluminum Oxide | wr | | wr | wr |
| Titanium Oxide | wr | | wr | wr |
| Calcium Oxide | wr | | wr | wr |
| Magnesium Oxide | wr | | wr | wr |
| Sulfur Trioxide | wr | | wr | wr |
| Potassium Oxide | wr | | wr | wr |
| Sodium Oxide | wr | | wr | wr |

| | | | | |
|---|---|---|---|---|
| **Coal** | 85% MCR Range | | 100% MCR Range | |
| | Minimum | Maximum | Minimum | Maximum |
| Heat Content, Btu/lb (HHV) | 10,000 | na | 11,600 | na |
| Hardgrove Grindability | 35 | 80 | 35 | 80 |
| As received Particle Size (inches) | 0 | 4 | 0 | 4 |
| Ash Fusion (reducing, soft, °F) | 2,050 | 2,680 | 2,050 | 2,680 |
| Volatile Matter (% DAF) | na | 47.0 | na | 47.0 |
| | | | | |
| Proximate Analysis | | | | |
| Volatile Matter | 20.0 | 40.0 (Note 4) | 30 | 36 |
| Fixed Carbon | 37.0 | na | 42 | na |
| Moisture | na | 15.0 (Note 7) | Na | 13.0 (Note 7) |
| Ash (Note 3) | 7.0 | 15.0 | 7.0 | 15.0 |
| | | | | |
| Ultimate Analysis | | | | |
| Carbon | 49.3 | 86.0 | 59 | 72 |
| Hydrogen | 3.2 | 6.0 | 3.9 | 5.3 |
| Nitrogen | 0.4 | 1.9 | 0.8 | 1.6 |
| Oxygen | 3.0 | 9.8 | 3.0 | 9.8 |
| Chlorine | na | 0.3 (Note 10) | na | 0.3 (Note 10) |
| Sulfur (Note 3) | 0.5 | 4.5 | 0.5 | 4.5 |
| Moisture | na | 15.0 (Note 7) | na | 13.0 (Note 7) |

| Coal (continued) | 85% MCR Range | | 100% MCR Range | |
|---|---|---|---|---|
| | Minimum | Maximum | Minimum | Maximum |
| Ash (Note 3) | 7.0 | 15.0 | 7.0 | 15.0 |
| Fluoride | na | (Note 5) | na | (Note 5) |
| Lead | na | (Note 5) | na | (Note 5) |
| Mercury | na | (Note 5) | na | (Note 5) |
| | | | | |
| Mineral Analysis of Coal Ash | | | | |
| Phosphorous Pentoxide | 0.04 | 3.0 | 0.04 | 3.0 |
| Silicon Oxide | 30.0 | 65.0 | 30.0 | 65.0 |
| Ferric Oxide | 2.9 | 45.0 | 2.9 | 45 |
| Aluminum Oxide | 18.0 | 36.0 | 18.0 | 36.0 |
| Titanium Oxide | 0.3 | 3.0 | 0.3 | 3.0 |
| Calcium Oxide | 0.5 | 9.0 | 0.5 | 9.0 |
| Magnesium Oxide | 0.1 | 2.0 | 0.1 | 2.0 |
| Sulfur Trioxide | 0.1 | 8.0 | 0.1 | 8.0 |
| Potassium Oxide | 0.1 | 4.0 (Note 9) | 0.1 | 4.0 (Note 9) |
| Sodium Oxide | 0.1 | 2.0 (Note 9) | 0.1 | 2.0 (Note 9) |

Note:

1. na = no limit applicable
2. All data is for fuel “as received”, and is percent by weight unless otherwise noted.
3. Coal minimum sulfur content is 0.5% given at least 12.0% ash. Coal minimum ash content is 7.0%, given at least 1.0% sulfur. For coals with sulfur content between 0.5% and 1.0%, and ash content between 7% and 12%, the minimum coal ash content as a function of sulfur content shall be as shown in Fig. 3-5.
4. The maximum coal volatile matter is 47% on a dry-ash free basis.
5. The emissions guarantee shall be based upon uncontrolled emissions as resulting from the combined inputs from fuel and limestone that do not exceed the following values:
   Lead - 0.00278 lb/MBtu (HHV)
   Mercury - 0.0000174 lb/MBtu (HHV)
   Fluorine (as HF) - 0.0106 lb/MBtu (HHV)
6. wr = within range
7. Surface moisture of the crushed fuel should be below 10% to avoid conveying and feeding hang-ups.
8. The total vanadium and nickel content in the fuel should not exceed 2,000 ppm. Operation at higher levels than 2,000 ppm will result in increased outages for unit cleaning and repairs.
9. The fuels fired in the boiler should have a combined acetic acid soluble sodium (Na) and potassium (K) content less than 0.05% (500 ppm) on a dry fuel basis to prevent bed sintering and agglomeration.
10. The chlorine level in the fuel should be less than 0.1% on a dry fuel basis to avoid corrosion and agglomeration problems.
11. Performance coal will be Eastern US coal.

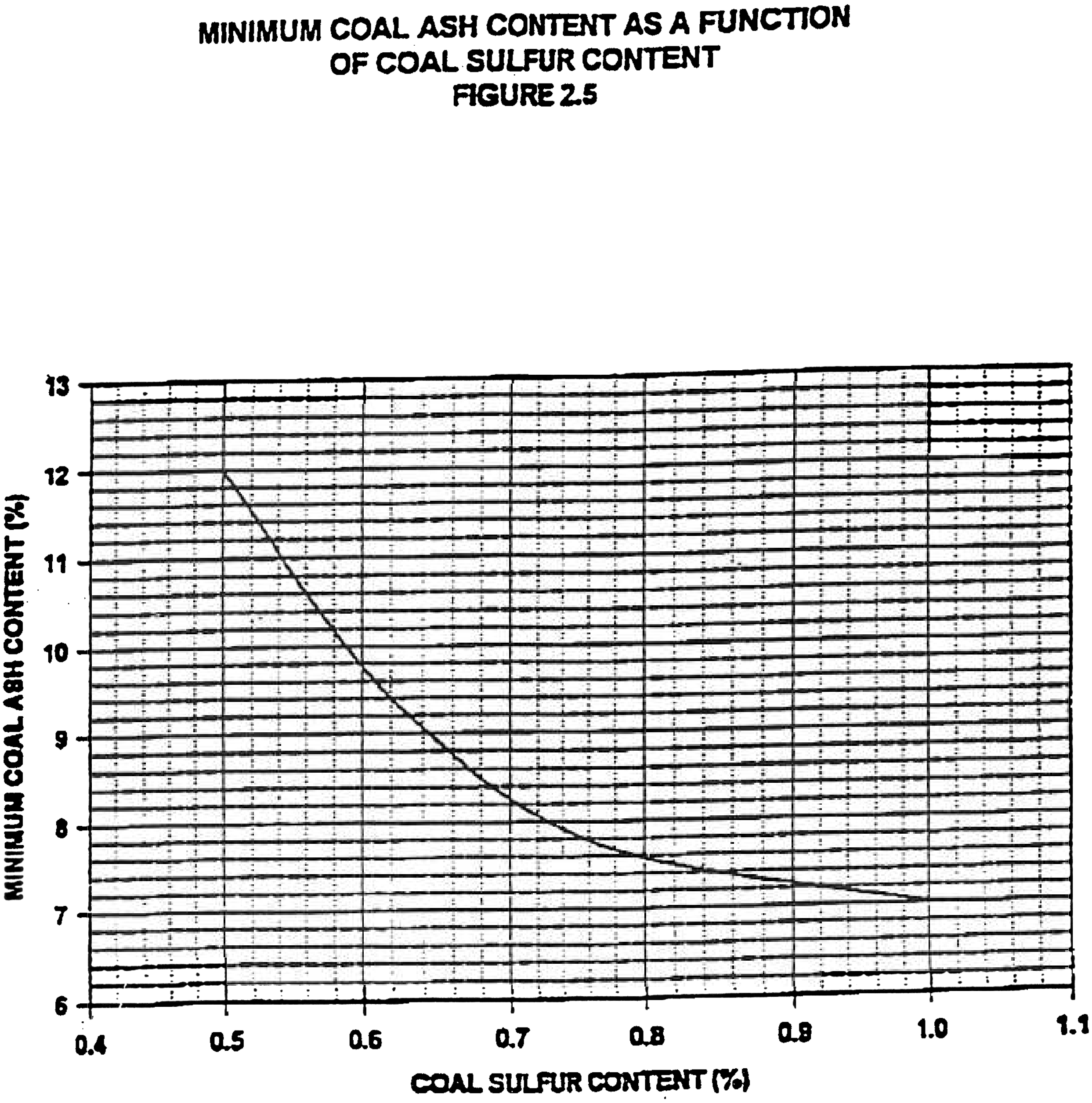


Figure 3-5 Minimum Coal Ash Content vs. Coal Sulfur Content

## 3.3 Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silo for each unit. The limestone preparation system flow diagram is shown on Drawing 9928-FD-L1 in Appendix 1. The limestone preparation system is designed for grinding limestone at a maximum feed size of 1 inch to a product size of -2000 microns meeting the CFB desired product distribution curve, with a residual moisture content of 1% maximum.

Three pneumatic transfer systems, one for each unit, and a shared spare system, are provided to convey the prepared limestone from the preparation building to the unit's silo. Each system is capable of transferring limestone to either Unit 1 or 2.

## 3.4 Air Quality Control System (AQCS)

To optimize overall plant performance, a polishing $SO_2$ scrubber was included in the design. The CFB boiler provides approximately 90% $SO_2$ capture via limestone injection, with the remaining capture from a semi-dry polishing scrubber via injection of lime. Overall $SO_2$ capture is over 98%.

Although CFB boilers can achieve 98% $SO_2$ removal, limestone utilization is reduced as removal efficiencies exceed 90% to 95%. The polishing scrubber allows reduction of the overall sorbent use, such that the savings in operating cost (sorbent, ash disposal) offset the capital and operating costs of the polishing scrubber. Another consideration in the decision to add the scrubber was the enhanced environmental performance regarding reductions of trace element emissions provided by the scrubber.

The polishing scrubber is a spray dryer/baghouse combination. The spray dryer utilizes a dual fluid nozzle atomized with air, and the baghouse is a pulse-jet design. A key feature of the polishing scrubber is a recycle system which adds flyash to the reagent feed, thus utilizing the unreacted lime in the flyash from the CFB boiler and reducing the amount of fresh lime required.

The polishing scrubber for each unit, provided by Wheelabrator Air Pollution Control, consists of a Spray Dryer Absorber/Fabric Filter (SDA/FF) Dry Scrubbing System to control $SO_2$ and acid gases, solid particulates, and heavy metals. Each system consists of:

- A Two Fluid Nozzle Spray Dryer Absorber (SDA)
- A Medium-Pressure Pulse Jet Fabric Filter (FF)
- A Feed Slurry Preparation System
- A common Absorbent Preparation System for both units, consisting of a Lime Storage Silo, redundant Vertical Ball Mill Slaking Systems, and redundant Transfer/Storage Tanks and pumps.
- A common Air Compressor System to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air. The compressors are provided with a closed loop cooling system. Waste heat from the compressor is used to preheat the reuse water feed to the SDA Feed Slurry System.

See Section 4.3 for a detailed description of the AQCS. Flow diagrams and mass balances for the AQCS are included in Appendix 1.

## 3.5 Turbine Generator and Balance of Plant Systems

The Unit 2 Turbine Generator was upgraded to maximize output and improve turbine heat rate as much as practical. The upgraded turbine heat balance diagrams are included in Appendix 1. The

HP/IP rotor, diaphragms, and inner casing were replaced with a GE Dense Pack design, which added four stages to the turbine, and increased turbine efficiency. The normal operating throttle pressure was also increased from 2400 psig to 2500 psig. In addition, the original mechanical linkage type turbine control system was replaced with a state-of-the-art Mark VI electrohydraulic control system, to allow better response to load changes and for complete integrated control, protection, and monitoring of the turbine generator and accessories. A new brushless excitation system was also installed on the generator, and a new turbine lube-oil conditioner was installed.

Unit 2 was originally designed to provide power to the JEA grid at 138kV. However, to better interface with present and future grid capabilities, the output from Unit 2 was increased to 230 kV. This required replacement of the generator step-up transformer and associated substation upgrades.

The once-through circulating water system was upgraded by replacing the original 90% copper/10% nickel heat-transfer surfaces in the condenser damaged by erosion/corrosion with modular bundles consisting of titanium tubes welded to solid titanium tubesheets. The existing circulating water pumps were replaced with larger capacity pumps. The traveling screens were replaced with those that have man-made basket material to increase their life. Debris filters were added to minimize condenser tube pluggage and possible damage. A sodium hypochlorite shock-treatment system was installed to prevent sea life from adhering to the titanium components of the condenser.

Upgrades to the condensate system in Unit 2 included upgrades to the condensate pumps and condensate booster pumps, replacement of the steam packing exhausters, replacement of the LP feedwater heaters, including replacement of the tube bundle in the lowest pressure heater (located in the condenser neck), replacement of the deaerator and storage tank, installation of a new condensate polisher, and installation of new chemical feed systems. The new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

Upgrades to the feedwater system in Unit 2 included replacement of the HP feedwater heaters, upgrades to the boiler feed pumps and fluid drives, and replacement of the boiler feed pump drive motor. Again, the new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

The capability of existing piping systems and components in Unit 2 was reviewed to confirm adequacy for the new operating and design conditions. If necessary, these systems and components were upgraded or replaced. Existing 2-½ inch and larger valves in Unit 2 were either refurbished or replaced. Nearly all 2 inch and smaller piping and valves in Unit 2 were replaced. Essentially all instrumentation in Unit 2 was replaced.

The original control systems in Unit 2 were replaced with a new distributed control system (DCS) provided by ABB Inc, to provide control, monitoring, and protection of the boiler, turbine interfaces, and balance of plant systems. Foster Wheeler provided the logic design for the CFB boiler, and Black & Veatch provided the logic design for the BOP systems, including provisions for turbine water induction prevention (TWIP). ABB provided the programming to implement the logic design for the boiler and BOP systems.

The Unit 2 auxiliary electric system (switchgear and motor control centers) was replaced because of equipment obsolescence. All power and control wiring was replaced due to the age of the wiring and because the existing control wiring was not segregated from the power wiring, thus not meeting the requirements of the new DCS system.

Other miscellaneous enhancements included the installation of additional air dryers and screw-type air compressors and the installation of titanium plate-type heat exchangers for the Unit 2 closed cooling water system, similar to those previously installed in Unit 1.

## 3.6 Fuel Handling System (Coal, Petroleum Coke, and Limestone)

The function of the Fuel Handling System is to receive coal, petroleum coke, and limestone from "Panamax" vessels (maximum vessel size which can pass through the Panama Canal) and to convey it to stock-out and storage areas. From there coal and petroleum coke are reclaimed and conveyed to the in-plant fuel silos; limestone is reclaimed and conveyed to the Limestone Preparation System.

The major components of the Fuel Handling System are as follows:

- Continuous Ship Unloader
- Belt Conveyors and Support Structures
- Domes
- Radial Stacker/Reclaimers
- Traveling Trippers
- Belt Feeders
- Belt Scales
- Magnetic Separators
- Metal Detectors
- Gates and Chutework
- Dust Suppression and Dust Collection Systems
- Screw Conveyors
- Vacuum Cleaning Systems
- Hoppers
- Telescopic Chute

See Section 4.5 for a detailed description of the Fuel Handling System. Arrangement Drawings of the Fuel Handling System are included in Appendix 3.

## 3.7 Ash Handling

The ash handling system transports bed ash from the outlets of the stripper coolers to the bed ash silos. It also transports fly ash from the economizer and air heater hoppers, as well as the baghouse hoppers, to the fly ash silos. Two sets of ash handling systems and associated equipment are provided, one for Unit 1 and the other for Unit 2.

See Section 4.6 for a detailed description of the Ash Handling Systems. Ash Handling System Piping and Instrumentation Diagrams are included in Appendix 1.

## 3.8 Reuse Water

Reuse water is domestic wastewater that has been treated and disinfected to a high degree and is reused for beneficial purposes. The reuse water used at Northside Generating Station (NGS) is treated wastewater from the District II Water Reclamation Facility. The wastewater is treated through primary, secondary and advanced treatment. During primary treatment, large solids are removed from the wastewater. Secondary treatment uses microorganisms to remove the remaining solids and organic material from the wastewater. After secondary treatment, the wastewater travels through cloth membrane filters, with a pore size of approximately 10 microns, to remove virtually all remaining solids. During advanced or final treatment, the wastewater is disinfected using chlorine or ultraviolet light to destroy bacteria, viruses and other pathogens.

Consumption of reuse water at NGS is expected to be more than 1 million gallons per day when all three units are operating. The reuse water is used for circulating water pump seals, boiler/precipitation area drains, polishing scrubbers, ash slurry preparation, and fuel handling dust suppression and wash down. Future uses may include irrigation.

Water Mass Balance Diagrams are included in Appendix 1 for reference.

## 3.9 Ash Processing and Storage

Two bed ash silos and two fly ash silos provide for short term (approximately three days) surge capacity and storage of bed ash and fly ash. The bed ash and fly ash from the silos is slurried using reuse water. The bed ash slurry and fly ash slurry are then blended together and pumped to the Byproduct Storage Area (BSA) using positive displacement GEHO pumps. A process diagram, with design flow rates, is included in Appendix 1.

Ash in the BSA sets up to form a low strength aggregate type material, with essentially the only water run-off being precipitation which falls in the area. This aggregate material is very likely suitable for use as fill material for road construction or other applications where fill material is needed. However, since this type of ash (CFB ash firing petroleum coke, with polishing scrubber and bag houses ash mixed with it) has never been generated previously, testing will be conducted on ash samples from this plant to determine its characteristics and suitability for use as fill material. After completion of testing and development of market uses for the ash, the intent is that all ash generated will be transported off site for use as fill material.

# 4.0 SYSTEM DESCRIPTIONS

The system descriptions in this section provide a technical description of the new equipment and systems associated with the Large-Scale CFB Combustion Demonstration Project at Northside. This section also includes system descriptions of existing major systems and equipment which were either upgraded or replaced in conjunction with repowering Unit 2.

## 4.1 CFB Boiler

The steam generator is a natural circulation, balanced draft unit that produces superheated and reheated steam by the recovery of heat liberated from fuel burned inside the furnace of the circulating fluidized bed boiler. The steam generator consists of water-cooled walls, plenum (windbox), wingwalls, division walls and a roof that make the furnace area of the boiler (four walls, roof and two division walls), three steam-cooled hot cyclones, and the heat recovery area (HRA or flue gas convection pass) with steam-cooled walls. Three integrated recycle heat exchangers (INTREX™ heat exchangers) are provided between the hot cyclone solids outlets (bottom of cone) and the furnace recycle inlets (INTREX™ return legs attached to the rear wall of the furnace). The INTREX™ and seal pot areas provide a seal (loop seal) between the lower furnace's positive pressure and the hot cyclone's negative pressure. The three INTREX™ heat exchangers contain, in series, two stages of intermediate steam superheating (ISH) and the final stage of superheating (FSH). The HRA section contains the primary stage of superheating (PSH) and the reheating section (RSH) of the boiler. Steam and water separation takes place inside the boiler's steam drum. Steam temperature control is done by spraying water (attemperators) to control the outlet temperature within limits.

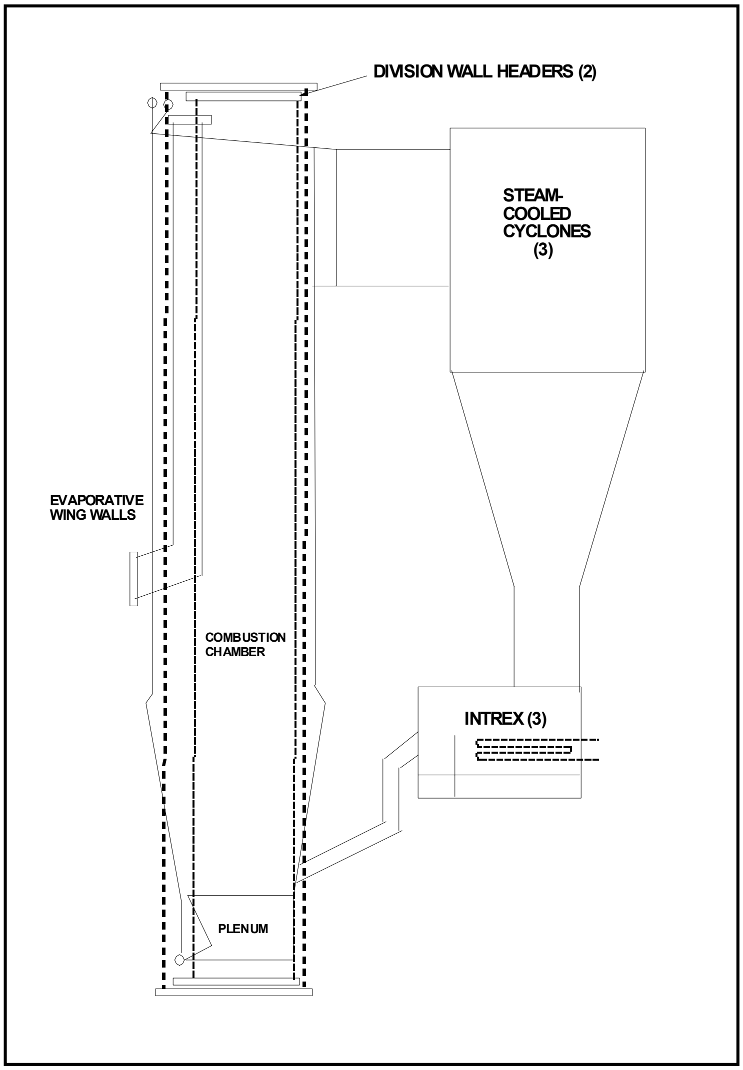


Figure 4-1 Furnace, Side View

Heat to generate steam comes from a fluidized bed of hot solids continuously circulated in the hot loop, from the furnace through the hot cyclones and returning to the furnace through the

INTREX™ heat exchangers. A typical normal bed is made of solid fuel (1% to 3%) and inert material made up of reusable bed ash that is mainly reacted (used) limestone and fresh (new) limestone plus ash left after the combustion process. Initially combusted in the bottom of the furnace, some solids from the bed are forced upward through the furnace giving off heat to the water in the waterwalls. The smallest solids traveling upward exit through the openings in the rear walls (hot cyclone inlets) to the three steam-cooled cyclone separators. Most of the solids in the gas stream remain in the hot loop with some fly ash guided with the gas stream through the high-temperature alloy plate-type vortex finder. The separated (good) bed material returns to the furnace through the INTREX™ heat exchangers. Flue gas exits out the top of the cyclones and passes through the HRA which contains the primary stage of superheating and the reheat steam section along with the economizer. After the HRA, the flue gas passes through the air heaters and the AQCS system (polishing scrubber and baghouse) before entering the induced draft (ID) fans.

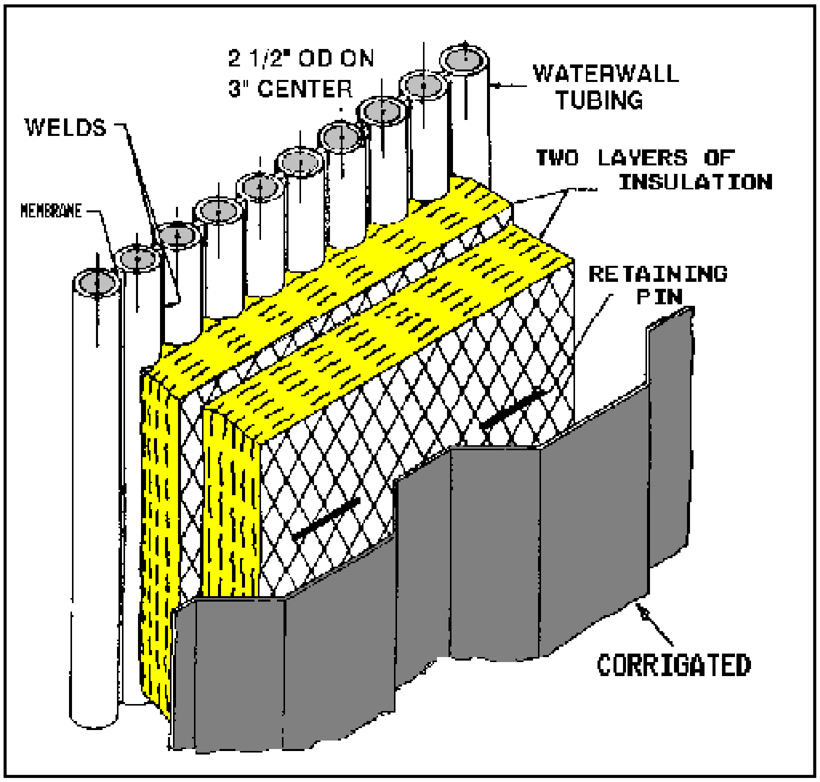


Figure 4-2 Typical Waterwall Section

The furnace consists of a water-cooled plenum (windbox) at the bottom of the boiler, where heated primary air is pressurized and passes upward through many pipes (grid nozzles) extending through the water-cooled floor (grid) to the furnace. Primary air is called the “below grid” airflow. The furnace is where bed material, including fuel and limestone, is fluidized with primary air from the windbox. This turbulent airflow mixes and transports solids (fuel and limestone) up the full height of the furnace, depending on its weight. Bed material is used as the heat transfer medium in the process. Primary air supplies most of the combustion oxygen (approximately 65%) for the process.

Additional combustion oxygen is supplied by upper and lower secondary air nozzles located on the front and rear walls of the furnace. Staged combustion is defined as adding oxygen to the controlled burning process at various heights in the furnace, resulting in many layers of secondary air in the furnace. Secondary air is called the “above grid” airflow.

Heat generated in the furnace is transferred to the water in the membrane waterwall tubing that forms the walls, division walls, wingwalls and roof of the furnace. There is no flame or fireball in normal CFB boiler operation. During start-up, a flame is present at the elbow in-duct burners below the plenum (windbox). Once bed temperatures are above 1400° F, solid fuel (coal and/or petroleum coke) combustion is self-sustaining and the elbow burners are not required.

The lower section of the furnace includes upper and lower secondary air ports (nozzles), front and rear wall solid fuel feed points, limestone feed points, a bottom ash removal system (stripper coolers), and the water-cooled air distribution grid (floor).

About 50% of the heat generated in the boiler is transferred to the waterwalls at full load. The circulating solids in this area assure that the heat transfer coefficients to the membrane wall tubing are typical of fluidized bed heat transfer values. In regions where the bed material flows change direction, heat transfer tubing is protected with abrasion-resistant refractory.

Ducts and airdrops supply primary and secondary air at various levels to the furnace for staged combustion. The primary air goes to the water-cooled windbox below the fluidizing grid and provides fluidizing and combustion airflow. Turbulence in the furnace causes fuel to mix vigorously and uniformly with the bed material. There is no defined fixed bed depth. The density of the bed varies throughout with the highest density at the lowest level where fuel is introduced.

Secondary air is introduced at levels above the grid in the furnace to assure solids circulation, to provide oxygen for staged combustion for $NO_x$ reduction, to supply air for continuous combustion in the upper region of the furnace, and to control excess oxygen.

Hot combustion gases and fly ash leave the steam-cooled cyclones and flow through the heat recovery area convective primary superheater, reheater and economizer sections. This part of the boiler is typical of any solid-fuel-fired boiler and includes sootblowing and ash removal features. In the convective heat transfer sections, flue gas flows through primary and secondary tubular air heaters that preheat primary and secondary air. From the two air heaters, flue gas is drawn through the AQCS system and exhaust to the chimney through the induced draft fans.

Three natural gas-fired elbow in-duct burners, located in the ductwork below the plenum (windbox), are primarily to provide heat input during start-up to bring primary air and bed temperatures in the furnace to solid fuel ignition temperature.

Fuel, petroleum coke and/or coal, is supplied to the six front wall feed points by six feeders. Fuel is supplied to the six rear wall feed points at the six INTREX™ return legs by two feeders and two parallel drag chains. Control of the fuel flow to the boiler is by gravimetric belt feeders. Primary air (sweep air) is mixed with the fuel in the front wall fuel-feed chutes and aids in transporting the fuel into the boiler to overcome the positive pressure in the lower furnace. Secondary air is added with the fuel at the rear wall fuel-feed air bustles to push the fuel into the boiler.

Powdered limestone for sulfur removal and bed makeup is fed at twelve feed points on the lower front wall and rear wall of the furnace, just below the solid fuel feed locations. Three separate "feed trains" supply the twelve limestone feed points. Volumetric variable speed rotary-type limestone feeders control the amount of limestone being blown into the furnace.

Bottom ash or bed ash removal is accomplished by four stripper coolers, two mounted on the boiler sidewalls and two on the front wall of the furnace. These devices strip and classify the bed material using hot and cold primary air and a closed cooling condensate water circuit. A variable speed ash drain is used to maintain the proper quantity and quality of bed material inventory.

A sootblowing (ash cleaning) system is used in the heat recover area (HRA) convection pass (backpass) to remove fly ash and limestone from heat transfer surfaces. A polishing scrubber and dust collector (baghouse) are the last devices in the flue gas path before it enters the induced draft (ID) fans. This dust collector filters the very small particles out of the flue gas before going through the ID fans and out the chimney.

The following paragraphs provide detailed information on the design and operating principles of the CFB boiler.

## 4.1.1 Furnace

The furnace is the combustion area of the boiler, made up of waterwalls welded together to form the gas-tight structure to contain the combustion process. The furnace is considered the "heart" of the hot loop. The hot loop circulation includes the furnace with division walls and wingwalls, steam-cooled cyclones with vortex finders, down spouts, and seals or INTREX™ heat exchangers with seal pots and return legs. In short, the equipment making up the circulating path of bed material.

The principle components of the furnace are:

- Water-cooled primary air plenum (windbox)
- Water-cooled fluidizing grid floor with many directional-type grid nozzles
- Water-cooled lower part (with refractory lining) and full-height division wall
- Water-cooled division walls
- Evaporative wingwalls
- Water-cooled upper part

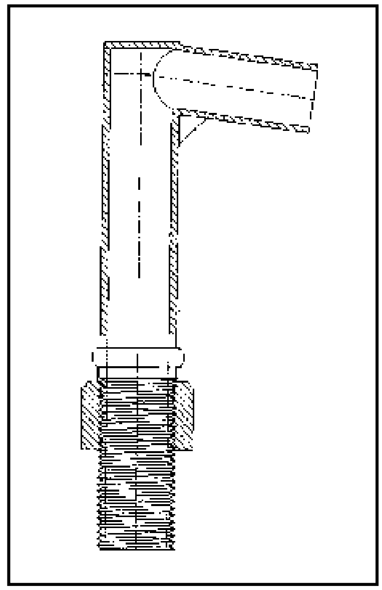

Figure 4-3 Directional Grid Nozzle

### 4.1.1.1 Water-Cooler Windbox and Fluidizing Grid

Primary air is delivered to the refractory-lined, water-cooled windbox by three ducts connected to the duct burners, air heaters and primary air fans. Heated primary air is contained in the windbox and is directed upward through the roof of the windbox. Many pipes (grid nozzles, see Fig. 4-3) extend upward through the water-cooled plenum (windbox) roof to direct the flow of air. Windbox pressure increases enough to overcome the pressure of the bed material above the grid. When enough pressure is generated, the airflow "breaks through" the inert bed material and the fluidizing process begins. These nozzles are used to fluidize the bed and to assist in the movement of bed material inside the furnace. Refractory is poured around the grid nozzles to protect the water-cooled floor from erosion.

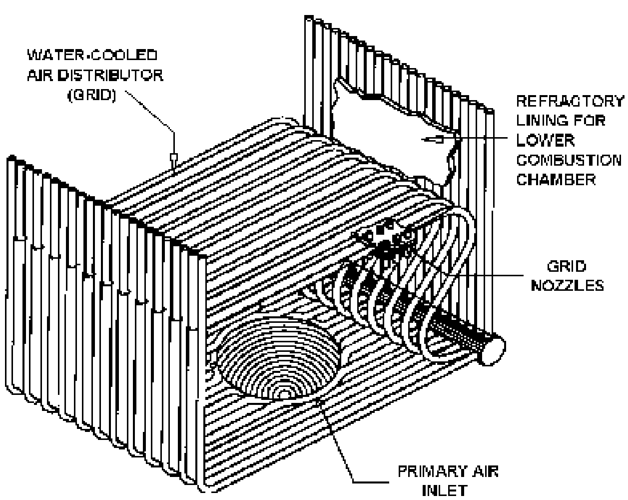


Figure 4-4 Water-Cooled PA Plenum (Windbox) and Grid Details

### 4.1.1.2 Water-Cooled Lower Part

The water-cooled lower walls of the furnace are made of 2" O.D. SA-210C-type tubes welded together with membrane. There are 341 tubes that make the front and rear walls. The sidewalls are 87 tubes wide. The grid floor is made of 171 3.375" O.D. SA-210C-type tubes welded together to form the grid floor. The lower vertical area (about the lower twenty-two feet) of the furnace is where the bed is the thickest and most turbulent. Primary airflow from the grid nozzles on the floor moves the bed around and then upward. Refractory is installed on all four walls, division walls, wingwalls and floor to protect the metal pipes from the abrasive fluidized bed material.

Above grid (or over-fire air), secondary airflow nozzles direct combustion air into the swirling bed mixture. The lower secondary air nozzles are about eight feet above the grid. The upper nozzles are about twenty feet above the grid. Air is brought in at these levels to control staged combustion of fuel without the forming of excessive temperatures, $NO_x$, or other pollutants and to control excess oxygen levels for safe boiler operation. Returning sized and recirculated bed material from the INTREX™ heat exchangers is added to this mixture in the lower part. With the further addition of fuel and limestone, a very dense atmosphere, under positive pressure, is formed. Two full-height division walls (see Fig. 4-5) are additional steam-generating heat surfaces that act to separate the furnace into three compartments and help to assure even ash loading at the inlet to the steam-cooled cyclones.

Many of the instruments used to monitor and control the CFB process are mounted on the walls and floor of the lower part. The bottom ash removal systems (stripper coolers) are attached to these lower parts. Access doors to the furnace are mounted on the lower front wall and side walls.

#### 4.1.1.3 Division Walls

Division walls are additional steam generating surfaces added to the furnace to keep overall size to a minimum. The upper division walls are made of 2.5" O.D. SA-210C-type tubes welded together with membrane to create a solid vertical wall extending from below the plenum upward, through the furnace and out the top and back to the steam drum. The lower part of the division walls is made of 3.5" O.D. SA-210C-type tubes welded together. There are openings in the lower part to allow bed material to flow evenly throughout the furnace.

#### 4.1.1.4 Evaporative Wingwalls

Evaporative wingwalls are additional steam generating surfaces added to the furnace to keep overall size to a minimum. These six wingwalls spaced evenly across the front of the furnace (see Fig. 4-6) are made of 2.5" O.D. SA-210C-type tubes welded together to form the “L” shape. The lower part of the “L” shape is about six feet across and the vertical sections are seventy-five feet tall. Water from the steam drum, through separate downcomers outside the front wall of the furnace, supplies water to the lower vertical header. Heated water passes inside the furnace, and upward, through the roof and back to the steam drum.

#### 4.1.1.5 Water-Cooled Upper Part

The upper part of the furnace is also made of 2" O.D. SA-210C-type tubes welded together with a membrane. This is the area where steam is generated when heat is transferred from the hot air/flue gas and bed material mixture to the water inside the waterwalls. Water is circulated down from the steam drum and distributed to the many inlet headers around the bottom of the furnace. Water rises through the membrane waterwalls along with steam generated to the outlet headers at the top of the furnace. Riser pipes connect the outlet headers to the steam drum. Because the walls are water-cooled, the temperature of the pipes is constant throughout the furnace and corresponds to the saturation temperature at the boiler steam drum pressure. The waterwalls in the upper part of the rear wall are bent to form the inlets to the steam-cooled cyclones.

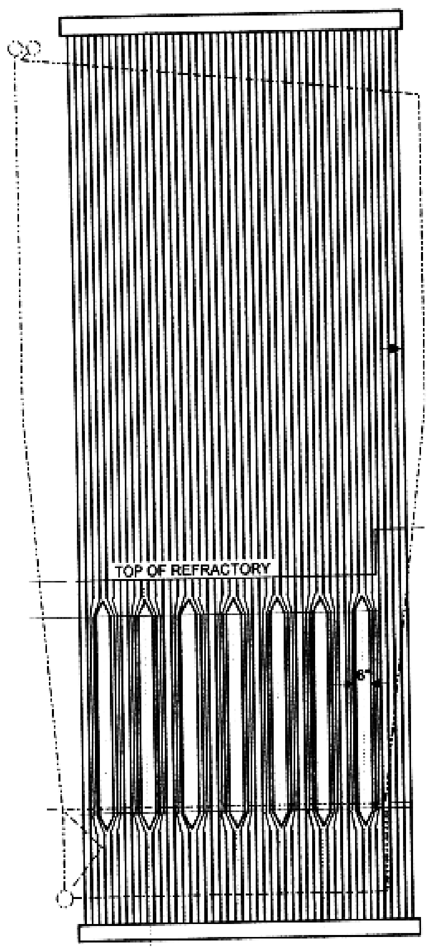


Figure 4-5 Full-Height Division Wall

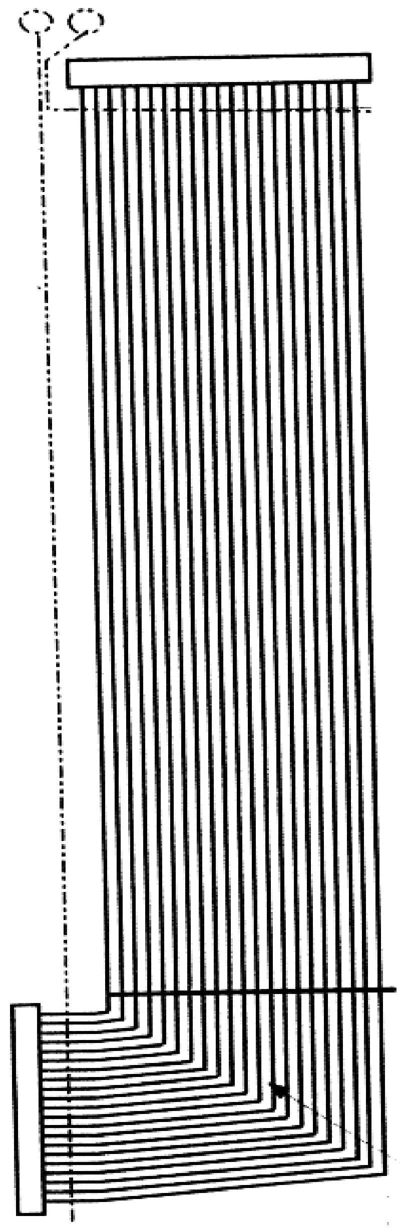

Figure 4-6 Evaporative Wingwall

### 4.1.2 Steam-Cooled Cyclones and Vortex Finders

Flue gases and bed material leaving the upper rear wall of the furnace enter the three steam-cooled cyclones. Each cyclone has a diameter of about twenty-four feet and an inlet height of about thirty feet. The overall height from the roof to the bottom of the cone is about sixty-five feet. Each cyclone is formed by shaping 192 individual 1.75" O.D. tubes. The distance between the tubes allows the shape of the cyclone cone and vertical sections. A thin layer of refractory, about two inches, is applied to the inside of the cyclones to protect the steam pipes from erosion.

Coarse bed material (good bed material) is then separated from the flue gases and fly ash based on the theory of centrifugal action.

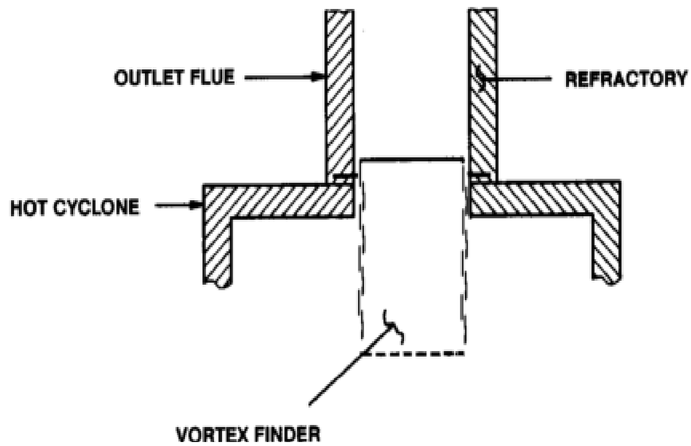


Figure 4-7 Vortex Finder Location

Separation of bed material from the flue gas is aided by a device called the vortex finder. This device creates a change in the direction of the flue gas and causes the heavier material to separate from the gas. The vortex finder (see Fig. 4-7) hangs from the top of the steam-cooled cyclone to improve separation efficiency. The vortex finder is made of rolled heat-resistant 253 MA material. The flue gases, together with the finer fly ash, leave the top of the cyclone and enter the boiler's HRA convection section. The good bed material is returned to the furnace through the INTREX™ heat exchangers and internal seal pots located at the bottom of each cyclone.

### 4.1.3 INTREX™ Heat Exchangers

Bed material separated in the steam-cooled cyclones flows downward inside the cyclones and through a connecting down pipe to the INTREX™ heat exchangers (see Figs. 4-8, 4-9, and 4-10). Each INTREX™ is divided into three sections, the middle or sealing section and the two superheater cells on the outside. A segmented windbox under the INTREX™ heat exchanger allows for distribution of air into the different sections. The INTREX™ heat exchangers are refractory lined, compartmentalized boxes that create the seal that separates the positive pressure in the lower part of the furnace from the negative pressure at the cyclones. The INTREX™ heat exchangers also prevent the backward (reverse) flow of air/flue gas up through the cyclone.

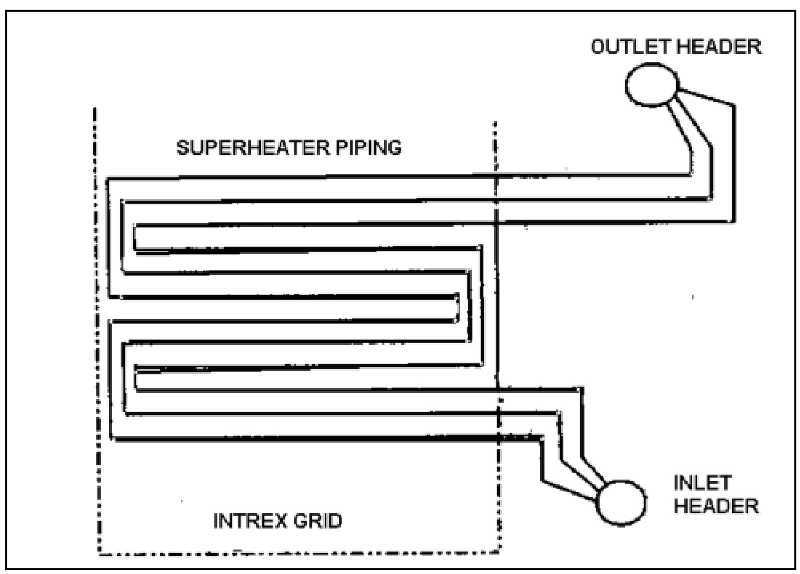


Figure 4-8 INTREX™ Heat Exchanger

When the boiler is operating, there must always be bed material in the INTREX™ heat exchanger sections. The bed material out of each cyclone enters the “seal pot” section. Bed material in the seal pot is fluidized by air from the seal pot blowers.

Fluidizing air penetrates the floor of the INTREX™ to keep the bed material fluidized so it will smoothly flow through the INTREX™ and back to the furnace. A large quantity of low pressure air from the INTREX™ and seal pot blowers is used to fluidize the bed material in various sections of the heat exchangers. Boiler operating conditions can cause the fluidizing air to the heat exchangers to vary.

Drains are installed on the floor of the INTREX™ to allow bed material to drain from the device when the boiler is shutdown and cooled for maintenance.

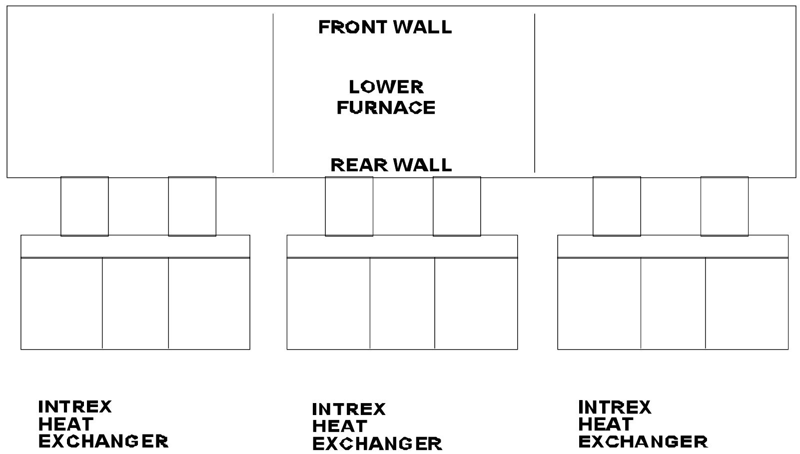


Figure 4-9 Lower Furnace with INTREX™ Heat Exchanger Layout

### 4.1.4 Refractory

Refractory is required in all Foster Wheeler CFB boilers to provide safe, reliable operation and maintenance of the boiler. There are two reasons for designing Foster Wheeler CFB boilers with refractory:

Insulation
Erosion Protection

#### 4.1.4.1 Insulation

Some areas of the CFB boiler are not constructed of pressure parts and are not cooled by the circulating water and/or steam, but are exposed to high temperature and high velocity flue gases. Depending on the configuration of the Foster Wheeler CFB boiler, these areas are typically the plate-construction-type INTREX™ heat exchanger and cross-over flue and ducts. In these areas where there is no heat transfer surface, the surface is lined with two layers of refractory or brick or castable pieces. The layer nearest the outer metal plate is the insulating layer; the second layer is an abrasion-resistant hard-face layer.

In addition to these non-pressure part areas, there are portions of the Foster Wheeler CFB boiler that require insulating type of refractories. These include wallboxes for air nozzles, elbow duct burners, fuel feed nozzles, INTREX™ to furnace connections, and in-furnace surface penetrations. These areas require an insulating type of refractory in the wallbox to reduce the temperature of the wallbox plate and create a seal around the penetration. Additionally, the upper and lower secondary air penetrations are designed with abrasion-resistant/ insulating refractories to protect the penetration

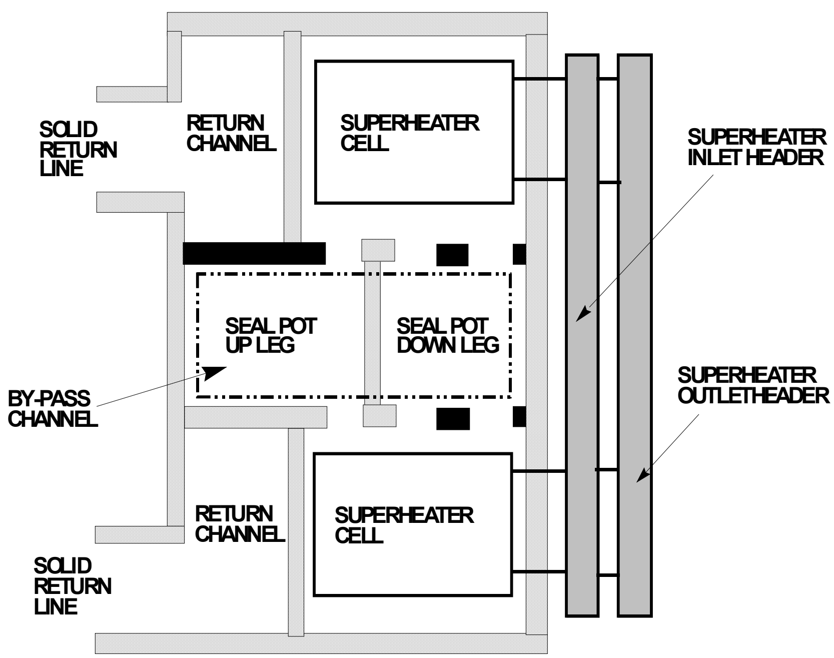


Figure 4-10 Side View of INTREX™ Heat Exchanger

interface from high temperature bed material.

#### 4.1.4.2 Erosion Protection

Prevention of erosion on boiler pressure parts is very important for long term reliability. Experience has shown that erosion in a CFB boiler can be reduced through attention to design details of pressure part arrangements and adding abrasion-resistant refractory coverage in key areas. Abrasion-resistant refractories selected for pressure part erosion protection also have low insulating characteristics, such that boiler heat transfer performance is not adversely affected. Refractory coverage of pressure parts for erosion protection in a CFB boiler is primarily in the furnace. These areas include:

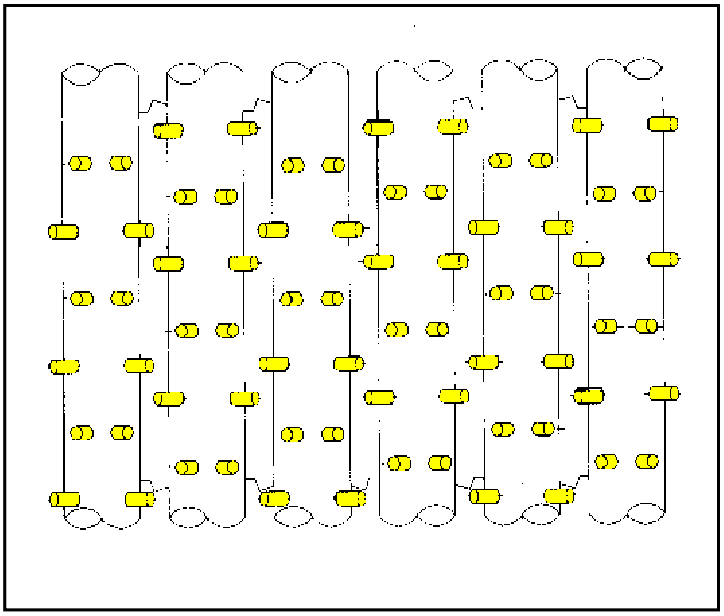
Figure 4-11 Waterwall Refractory Studs

**Lower furnace** – The lower part of the furnace is considered the portion that has the highest density of bed material. The bed material is mixed with incoming fuel and limestone and fluidized by the grid nozzle airflow. The smaller particles are entrained in the upward flow. As each particle reaches terminal velocity, it moves to the outside, slides down the walls and falls back toward the grid floor. The particles in this area are very abrasive. The refractory is started from the grid floor to the transition from furnace vertical wall to sloped wall, about twenty-two feet. Refractory (gunite) is sprayed on the walls and held in place by metal studs welded to the waterwall piping.

**Penetrations and discontinuities** – CFB boiler operating experience has shown that erosion in the majority of the furnace does not occur if there are no discontinuities that would change the direction of downward and upward flowing bed particles. Thus, the system is designed to eliminate unnecessary discontinuities. In locations where discontinuities must exist, such as in-furnace surface penetrations and the furnace flue gas outlet, erosion protection is designed into the systems with shielding (weld overlay) or refractory coverage, or a combination of protection methods.

**Furnace flue gas exits** – This area is subject to high velocity flue gas with bed material changing direction. The flue gas is funneled toward the furnace flue gas exits. The pipes adjacent to the inlet on either side and above and below are protected with refractory.

**In-furnace heat transfer surfaces** – For evaporative wingwalls and division walls, refractory is applied to the bottom sections of the wingwalls and division walls (the pipes that are bent and run perpendicular to the flow of the circulating bed) to protect from erosion.

**Pressure parts not associated with the furnace** – In various Foster Wheeler CFB boiler configurations, there are pressure parts after the furnace that may require refractory coverage for erosion protection. Depending on the configuration of the specific boiler, these areas may include the water-cooled or steam-cooled cyclones, INTREX™ heat exchanger, steam-cooled cross-over, and cross-over interface with the convective sections of the boiler. In general, pressure parts after the furnace will have refractory applied only if that area will be subjected to high velocity flue gas flows and/or bed material that is changing its direction of flow at the face of the pressure part.

In addition to pressure part coverage, there are areas of the boiler with non-pressure parts that may be subjected to erosion for the same reasons mentioned above (high gas velocity, changing directions, etc.). These areas include plate-construction type cyclones, INTREX™ heat exchangers and cross-over flues and ducts.

### 4.1.5 Heat Recovery Area (HRA)

After leaving the steam-cooled cyclones and vortex finders, hot flue gas passes through the refractory lined cross-over duct and enters into the top of the dual-element HRA convection heat transfer section of the boiler (see Fig. 4-12). The flue gas splits and flows into the primary superheating section and into the reheat steaming section. Flow through these two sections is influenced by two dampers at the outlet of each section. As flue gas flows downward in this steam-cooled section, heat is transferred from the hot flue gas into the reheat steam and primary superheat steam. The economizer is located directly below these steam sections. At the bottom of the economizer are the HRA ash hoppers connected to the ash removal system.

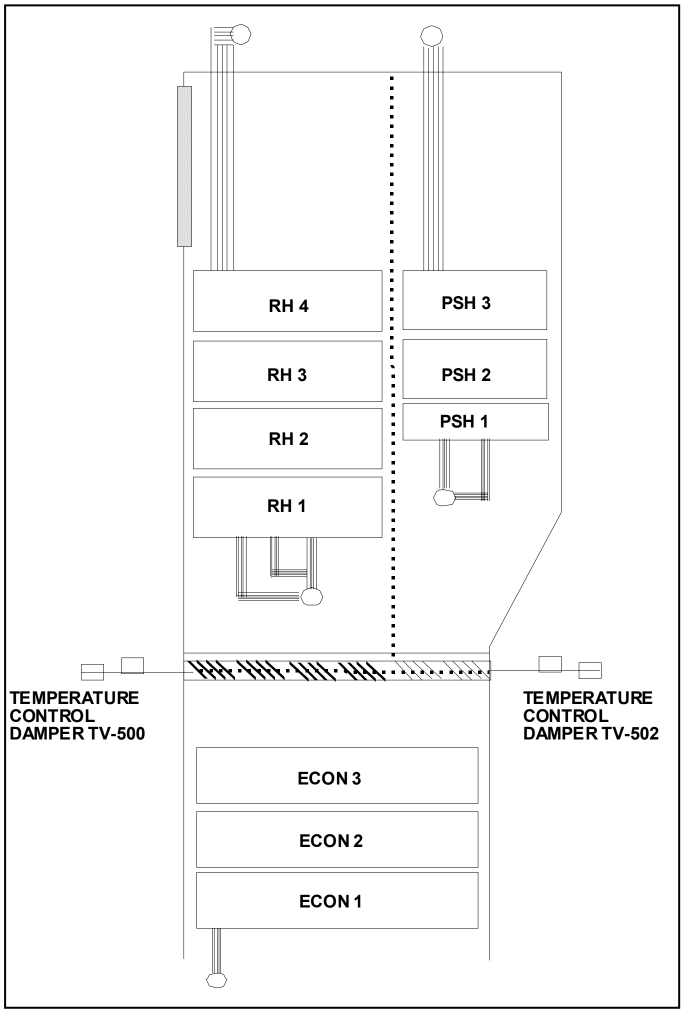


Figure 4-12 HRA Section of the Boiler

Immediately after the HRA are two air heaters, primary and secondary. The vertical tubular air heaters are devices that heat primary and secondary air before it enters the boiler. Air is heated as it passes outside the tubes, and the hot flue gas gives up its heat as it flows inside the tubes. Special “rifling” inside these tubes keeps the air heater tubes clean. These devices improve the efficiency of the boiler by capturing some of the heat that would otherwise go out the chimney. These devices also cool the flue gas to allow for safe passage through the AQCS.

### 4.1.6 Superheaters and Reheaters

Flue gas flow through the HRA convection pass is through the reheater section (RSH) and the primary superheater section (PSH) allowing heat to transfer from the flue gas into the steam. These are hanging heat transfer tube coils suspended across the flue gas channels. The other stages of superheating are accomplished inside the INTREX™ heat exchangers.

### 4.1.7 Economizer

After superheater and reheater elements in the HRA, the moderately hot flue gases and fly ash pass across the water-filled economizer pipes (see Fig. 4-13). Each economizer pipe is 2" O.D. and made from SA178C-type metal. This is where hot feedwater enters into the boiler before going to the steam drum. The economizer is a serpentine tube arrangement in which flue gas flows from top to bottom and feedwater enters at the bottom and flows to the top.

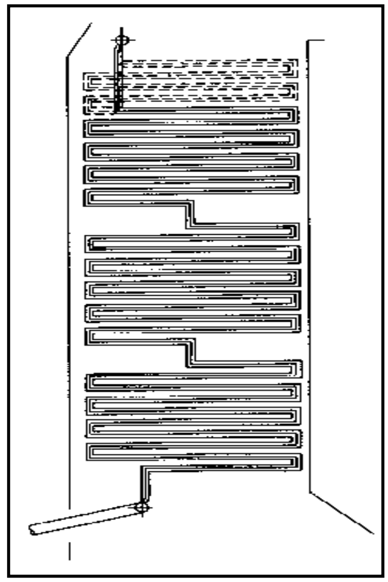

Figure 4-13 Economizer

### 4.1.8 Seismic Stops

In addition to the boiler's structural steel supports, there is a system of guides and stops, located at various elevations to help guide the movement of the boiler. This support system guides the boiler during normal expansion and, in case of an earthquake, transmits the seismic forces to the steel structure around the boiler.

### 4.1.9 Buckstays

There is a system of support steel (I-beams or buckstays) around the furnace to prevent the square box-like structure from deforming under adverse conditions. The furnace must be free to expand and contract during normal heating and cooling conditions. The casing of the boiler is stiffened with a series of I-beams attached to the waterwalls by bolts that allow lateral and vertical movement and are pivoted at the corners (see Fig. 4-14). This allows controlled expansion with the most amount of stability.

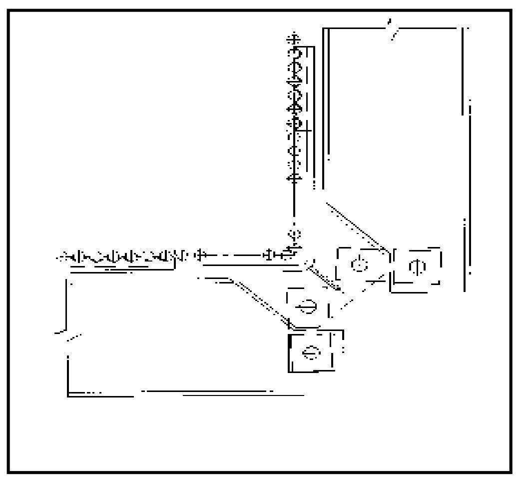

Figure 4-14 Buckstay Corner Connection

### 4.1.10 Front Wall Fuel Feed System

For the JEA boilers, three fuel feed silos direct the flow of fuel to six feeders that discharge into six feed spouts on the front wall. Six individual, variable-speed gravimetric belt feeders control coal and/or petroleum coke flow to the front wall. Each feeder discharges directly to a fuel feed spout where primary air is added to the fuel to help move the fuel into the lower part of the furnace. The flow of fuel is controlled by the fuel master according to the steam demand (pressure) signal from the DCS.

### 4.1.11 Rear Wall Fuel Feed System

The rear wall fuel feed is accomplished by two silos feeding two individual variable speed gravimetric belt feeders to control coal and/or petroleum coke flow to the boiler. Each feeder then discharges to a variable speed drag chain that delivers fuel across the rear of the boiler. Each drag chain has three discharge points and goes to a return line from an INTREX™ heat exchanger return leg. On the bottom of the drag chain are two flow control valves that set the amount of fuel for each feed point. Just below each discharge point of the drag chain is an "air bustle" where secondary air is added to the fuel feed to help move the fuel into the lower part of the furnace. The flow of fuel is controlled by the fuel master according to the steam demand (pressure) signal from the DCS.

### 4.1.12 Natural Gas Elbow In-Duct Burner System

Three natural gas-fired elbow in-duct burners are used for boiler start-up. These burners are located on the ground floor in parallel to the primary air ducts below the plenum under the furnace. Each burner has its own primary air booster fan and control dampers to supply combustion air when the burner is in operation. Each burner is complete with a separate burner management control and safety logic. When not in use, the burners and booster blowers are shutdown. The main purpose of these burners is to control the heat that warms bed material to a temperature at which the fuel safely ignites so that fuel feeding can start. Gas is distributed and controlled at each burner's gas rack. A separate control system in the DCS and Burner Management System (BMS) allows safe boiler operation.

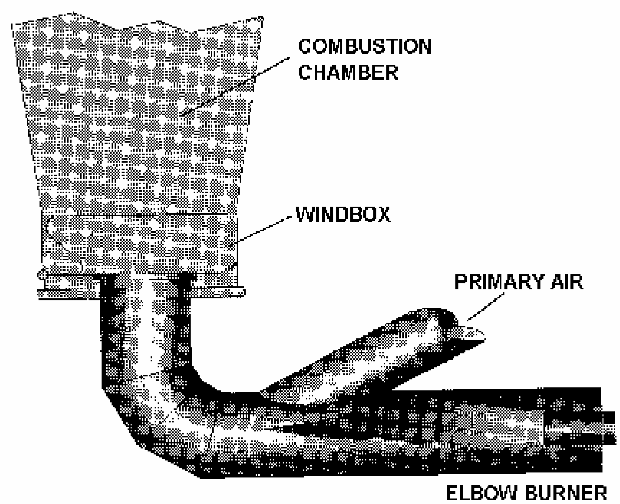


Figure 4-15 Gas-Fired Elbow In-Duct Burner

### 4.1.13 Sootblowing System

The boiler's HRA is equipped with thirty-six steam-powered cleaning (sootblower) stations that will clean the heat transfer surfaces of the convection pass when the boiler is above 50% MCR steam flow. Sootblowers are not required in the furnace, hot loop parts or cyclones because operating temperatures are below the fusion point of ash. Sootblowers are only required in the HRA convection section (backpass) of the boiler. Two different types of sootblowers are used on the boiler. Full retractable sootblowers are used in the very hot upper areas, and half-retractable sootblowers are used in the cooler lower areas where the temperature has been reduced. These sootblower lances are made of heat-resistant steel. The actual sootblowing sequence and frequency is determined by operating experience. Each sootblower is motor driven and can be controlled either locally, from a PLC, or from the DCS.

### 4.1.14 Heat Recovery Area Ash Hopper

A small part of the fly ash that passes through the HRA convection pass falls out of the flue gas as it turns and leaves the HRA on the way to the tubular air heaters. To remove this ash, hoppers are located under the backpass. The hoppers are made of insulated carbon steel plate and steeply sloped to allow the flow of ash. Fly ash is removed from the flue gases by a fabric filter baghouse or other type of dust collector.

### 4.1.15 Bed Ash Removal System

The need to remove coarse bed material from the furnace and control the amount of bed material in the furnace has lead to the development of stripper coolers. On each side wall and the front wall of the furnace are devices called “stripper coolers” that remove, classify and cool coarse ash (bed material) from the furnace. Directional nozzles inside the solids transfer line (inlet to the stripper cooler) force coarse material from the furnace into the stripper cooler. Hot and cold primary air is used in the stripper cooler to strip (classify) and cool the bed ash. Directional air nozzles on the floor of the stripper cooler direct ash into and through the stripper and cooler sections.

There are condensate-filled cooling coils in the Cooler 2 and Cooler 3 sections which use condensate to remove heat from the ash. There are also emergency water spray nozzles located in the stripper and Cooler 1 sections which can spray a small quantity of potable water into the ash if required for additional cooling. The spray system is automatic and will cycle on and off based on measured ash temperature in several sections of the stripper cooler. The system can also be activated by the plant operator. The spray will not be needed during normal operating conditions.

The cooled material is removed from each stripper cooler through a variable speed rotary valve. The rotary valve discharges into a drag chain system which conveys it to a surge hopper for pneumatic conveying to the bed ash silo. The rotary valve speed is controlled by ash removal demand based on boiler bed ash level. There are also temperature and pressure interlocks to ensure that there is ash in the stripper cooler and that it is below a maximum discharge temperature. The stripper coolers are designed for continuous operation.

### 4.1.16 Drains, Vents, and Blowdowns

The boiler is supplied with a blowdown tank that is fitted with a manifold for the various hot drains and blowdowns. Connections are normally provided for blowdown from the bottom of the furnace, steam drum, downcomers and economizer, blowdowns from steam drum level gauges, blowdown from the steam drum level controller, the superheater and reheater header drains, the sootblower piping drains and the steam air heater condensate drain.

In addition, miscellaneous drains are normally brought to the blowdown tank sump, such as drains and vents from the economizer, vents from the upper headers and high points in the pipe work, steam drum vents, atomizing steam condensate drains, and drains from the safety valve lines and the silencers.

Blowdown valves are usually grouped together for ease of operation. The first valve acts as the shutoff valve and the second as the blowdown valve. Most blowdowns and drains have a double block valve arrangement. The valve closest to the source is called the root block valve. The second valve is called the block valve. The root block is always open or closed and is not used to throttle or control flow. The second valve, the block valve, is used to throttle or control flow.

Using this procedure, the blowdowns and drains can be isolated with the boiler running if maintenance has to be performed on the control or throttling valve.

## 4.2 Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silo for each unit. The limestone preparation system flow diagram is shown on Drawing 9928-FD-L1 in Appendix 1.

The limestone grinding system consists of three rod mills with accessories. The mills are sized for grinding limestone at a maximum feed size of 1 inch to a product size of -2000 microns meeting the CFB boiler desired product distribution curve, with a residual moisture content of 1% maximum.

Raw limestone from limestone conveyors L2, L3, and L4 feeds through a double flap valve into each impactor/dryer mill. A natural gas-fired hot air generator provides hot air to the mill when the feed moisture exceeds product moisture content, which dries the limestone during grinding.

The limestone is crushed in the rod mill. The mill is supplied with a variable speed drive to vary the mill speed. This is required to regulate the product gradation. The limestone discharges from the mill shell peripheral discharge openings through one of the trickle valve airlocks to an elevating belt conveyor. Most of the ground limestone goes to two vibrating screens where it is sized. The oversized material from the screens goes back to the mill. Gases are pulled through the mill for drying and de-dusting purposes. A portion of the ground limestone is carried to the dust collector. The major portion of the product comes from the undersize of the screens while a small fraction comes from the dust collector. These two product streams are collected and sent to the storage silo as product for feeding to the CFB boiler.

The limestone preparation building is an enclosed structure with siding. The building includes multi-levels for supporting equipment and access, personnel doors, equipment access doors, and a ventilation system.

Three pneumatic transfer systems are provided to convey the prepared limestone from the preparation building to the unit’s silo. Each silo has a bin vent filter to control dust emissions. Each system is sized for 50 tph capacity and is capable of transferring limestone to either Unit 1 or Unit 2.

Two compressors are provided for the dust collection system for fabric filter cleaning and instrumentation air requirements. Shutoff dampers are provided in the system for controlling the hot air requirement for the dryer/mill. A louver damper is provided at the inlet of each mill fan. The system includes all ducts, pipework, electrical and instrumentation as required for a complete system. A sound suppression hood is provided for the grinding mills to maintain the sound level of 85 dBA at three feet distance.

The control system for the limestone preparation system uses a programmable logic controller (PLC) with a CRT-based operator interface located in the Material Handling Control Room. A digital communication interface is furnished to tie this local control system into the plant’s Distributed Control System (DCS).

The Limestone Preparation System is principally controlled and monitored from the local CRT control panel, located in the Material Handling Control and Electrical Equipment Building Control Room. The main plant control room via the DCS interface has supervisory control of and monitoring capability for the limestone preparation system.

The control system graphical displays are of the process diagram type and contain real time information on process conditions and equipment status.

## 4.3 Air Quality Control System

The polishing scrubber for each unit, provided by Wheelabrator Air Pollution Control (WAPC), consists of a Spray Dryer Absorber/Fabric Filter Dry Scrubbing System to control $SO_2$ and acid gases, solid particulates, and heavy metals. Each system consists of:

- Two Fluid Nozzle Spray Dryer Absorber
- Medium Pressure Pulse Jet Fabric Filter
- Feed Slurry Preparation System
- Common Absorbent Preparation System for both units, consisting of a Lime Storage Silo, redundant Vertical Ball Mill Slaking Systems, and redundant Transfer/Storage Tanks and pumps.
- Common Air Compressor System to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air. The compressors are provided with a closed loop cooling system. Waste heat from the compressor is used to preheat the reuse water feed to the SDA Feed Slurry System.

### 4.3.1 Dry Scrubbing System

The Dry Scrubbing System was designed to provide $SO_2$ and acid gas (HF and HCl), solid particulate (fly ash), and heavy metal control from each of the circulating fluidized bed boilers. The Dry Scrubbing System consists of a Spray Dryer Absorber (SDA), Fabric Filter (FF), and Feed Slurry Preparation System for each boiler.

Flue gas from the CFB boiler air heater outlet enters the top of each SDA. (See Drawings 3847-3-001/002, Process Flow Diagrams, in Appendix 1, and 3847-1-100/101/103, General Arrangement, in Appendix 3). A lime slurry is atomized into the flue gas in the SDA. The fine spray droplets absorb acid gases ($SO_2$, HF, and HCl) from the flue gas. The heat of the flue gas evaporates the slurry water, creating a solid particle. The flue gas is then ducted to a fabric filter where the fly ash from the boiler and the dried reaction products from the SDA are collected. Additional acid gas removal occurs as the flue gas passes through the dust cake on the fabric filter bags.

Flue gas enters the FF inlet plenum and is ducted to eight separate compartments. Flue gas enters each compartment and is directed up and around the bags. Each bag is supported on a cage. When flue gas passes through the bags, the boiler fly ash and reaction products are filtered. Flue gas passes from the clean side of each compartment through an outlet plenum ductwork, and then into the ID Fans. The bags are periodically cleaned by a reverse jet of pulse air. The dislodged solids fall to a hopper and are pneumatically conveyed to either the Recycle Surge Bin or to the Fly Ash Silo for final disposal.

The feed slurry to the SDA consists of lime slurry and recycle slurry. The lime slurry is supplied by the Absorbent Preparation System. Recycle slurry is prepared by mixing a portion of the fly ash and reaction products collected in the SDA and FF with water. This is done to improve the utilization of lime and minimize operating costs.

### 4.3.2 Absorbent Preparation System

Pebble lime is delivered to the site in self unloading trucks and stored in a common lime silo. Pebble lime is fed from the silo to two redundant Vertical Ball Mill Slaking Systems utilizing a live bin bottom feed system.

Each Vertical Ball Mill Slaking System consists of a

- Lime Feeder
- Feed Chute
- Vertical Ball Mill Slaker or Vertimill
- Separating Chamber
- Mill Recycle Feed Pump

The purpose of the slaking system is to mix water with lime and produce a slaked lime (calcium hydroxide) slurry. The Lime Feeder meters pebble lime into the feed chute where water addition is controlled to produce a nominal 25 wt % slurry. The water and slurry drop into the Vertimill. The Vertimill consists of a vertical mixing chamber, with a center screw agitator and grinding balls. The agitator mixes the pebble lime, water and balls, and the balls grind the pebble lime, promoting the slaking reaction. The slurry overflows to the separating chamber where oversized particles are pumped back to the bottom of the Vertimill.

Lime slurry overflows the Separating Chamber to the Lime Slurry Transfer Tank. Lime Slurry is pumped from the Transfer Tank to the Unit 1 and Unit 2 Lime Slurry Storage Tanks.

The slaking system is designed to process dry pebble lime at 30 tph and is also designed to be capable of processing Boiler Bed Ash, which contains unreacted lime, at 20 tph. The Boiler Bed Ash option is for future implementation. Bed ash would be made up into a 20 to 35 wt % slurry and pumped to the ball mill.

A Bin Vent Filter is provided to capture dust emissions from the lime silo created by the truck fill operation. A fan vent scrubber (wet scrubber) is provided to collect the dust and water vapor (steam) generated in the ball mill.

### 4.3.3 Air Compressor System/Global Cooling System

The Air Compressor System is designed to provide atomizing air, instrument air, and pulse air to the Dry Scrubbing System. A Glycol Cooling System is designed to cool the air compressors and atomizing air. Heat from the system is used to preheat the water for the Feed Slurry Preparation System.

### 4.3.4 Ductwork

Ductwork is provided to convey flue gas from the CFB boiler air heater to the SDA, FF, ID Fans, and into the chimney. Isolation dampers are provided for the ID Fans.

### 4.3.5 Design Parameters

The Dry Scrubbing System is designed to provide $SO_2$ and HF, solid particulate, and heavy metal removal from the flue gas stream. A calcium hydroxide slurry ($Ca(OH)_2$) is atomized into the flue gas using a Spray Dryer Absorber (SDA). (See process flow diagrams, Drawings 3847-3-001 and 002 in Appendix 1.) $SO_2$ and HF are absorbed by the slurry, while the heat of the flue gas evaporates the slurry water, and cools the flue gas. The cooled gas is ducted to a fabric filter where solid particulates (fly ash and dried reaction products) are collected. Cooling the flue gas promotes the condensation of heavy metals (mercury and lead) and sulfuric acid mist, allowing them to be captured as a solid or aerosol in the fabric filter.

Design Removal Emission levels are:

| | |
|---|---|
| $SO_2$ | Outlet concentration less than 0.15 lb/mmbtu (24 hr geometric mean) |
| Solid Particulate | Outlet concentration less than 0.011 lb/mmbtu |
| PM 10 | Outlet concentration less than 0.011 lb/mmbtu |
| Sulfuric Acid Mist | Outlet concentration less than $4.0 \times 10^{-4}$ lb/mmbtu |
| Hydrogen Fluoride | Outlet concentration less than $1.57 \times 10^{-4}$ lb/mmbtu |
| Lead | Outlet concentration less than $0.26 \times 10^{-4}$ lb/mmbtu |
| Mercury | Outlet concentration less than $0.105 \times 10^{-4}$ lb/mmbtu |
| Opacity (%) | Less than 10% (6 min avg.) |
| Fugitive Dust | Lime Silo/Fabric Filter Outlet and Ball Mill Vent Scrubber Outlet concentration less than 0.005 gr/dscf |

## 4.3.6 Process Descriptions

### 4.3.6.1 SDA Operation/$SO_2$ and Acid Gas Removal

Flue gas enters the top of the SDA vessel through a perforated plate flue gas distribution system which creates a plug flow gas pattern. A total of sixteen two fluid nozzles are used to atomize lime/recycle slurry into the flue gas. The $SO_2$ and HF removal process occurs in two separate phases. In the first phase, the $SO_2$ and HF are absorbed by the atomized slurry droplets. The $SO_2$ reacts with the Ca $(OH)_2$ in the slurry to form calcium sulfite ($CaS0_3$ ½ $H_2O$). Some of the calcium sulfite is further oxidized to calcium sulfate ($CaSO_4$ $2H_2O$). The HF reacts with the $Ca(OH)_2$ to form $CaF_2$.

Evaporation of the slurry water in the droplets occurs simultaneously with these reactions. The flue gas and solid particulate are then ducted to a fabric filter where the solid materials are collected from the flue gas. In the second phase, $SO_2$ and HF are adsorbed onto the dried particle surface of the filter cake on the bags.

The efficiency of the process is improved as the spray dryer absorber exit temperature decreases and approaches the water (adiabatic) saturation temperature. A lower exit temperature increases the time required to dry the slurry droplet, thereby increasing the reaction time of the more efficient liquid absorption step. $SO_2$ and HF adsorption onto the filter cake surface of the dried reaction products is also enhanced. The moisture aids diffusion of absorbed $SO_2$ and HF from the surface allowing more absorption on the surface during the second phase of removal in the FF. The total amount of slurry feed to the process is controlled to obtain the required $SO_2$ and HF removal while producing a dry product. The system is designed to operate over an outlet temperature range of 155° to 175° F, which is 30° to 50° F above the flue gas adiabatic saturation, or wet bulb, temperature. The spray dryer absorber is designed to provide twelve seconds of flue gas residence time at these conditions.

Solids collected in the SDA and FF are recycled back into the process to minimize the use of purchased lime. The recycled materials contain two sources of lime. There is unreacted lime (CaO) in the flyash leaving the CFB boiler. There is also unreacted calcium hydroxide in the reaction products from the SDA. These materials are mixed with water in the Recycle Mix Tank. The recycle slurry is then blended with lime slurry from the Lime Slakers and pumped to the SDA.

The Recycle Slurry has a considerable amount of inert materials including fly ash from the boiler, calcium sulfate from the CFB operation, and calcium sulfite/chloride reaction products from the SDA/FF operation. There is a limit to the slurry solids content that can be pumped and atomized in the SDA. The system controls are designed to produce a fixed recycle slurry concentration. Lime slurry will be blended with the recycle slurry at two different points, depending on $SO_2$ removal requirements and boiler outlet temperature. Slurry is added with recycle solids and water in the mix tank and/or with the recycle slurry prior to being pumped to the SDA.

The amount of water that can be fed to the SDA is limited by the set outlet temperature; therefore, the higher the SDA inlet temperature, the greater the amount of water that can be added. The amount of water then limits the amount of solids that can be fed, both lime and recycle, to the SDA. The controls maximize the use of recycle materials and minimize the use of lime slurry while maintaining the required $SO_2$ emission level.

#### 4.3.6.2 Fabric Filter

Each boiler is supplied with an eight compartment Fabric Filter Pulse-Jet Dust Collector. Each compartment contains twenty-six rows of forty Ryton bags supported on wire cages.

Flue gas exits the SDA, passes down the FF inlet plenum and is distributed to the eight FF compartments. Eight duct elbows connect the bottom of the plenum with the individual FF hoppers. Gas is directed upward toward the top of the bags by an internal baffle system.

The filter bags are supported on wire cages suspended from the FF tubesheet at the top of each compartment. When flue gas passes through the fabric, the fly ash and SDA reaction products entrained in the flue gas are filtered.

Flue gas flow is primarily horizontal and downward past the bags. Dust is cleaned from the bags by pulsing with dried, compressed air (35 psig). Dust falls into the hopper and is conveyed away by the Ash Handling System.

The filter bags have the following physical characteristics:

| | |
|---|---|
| Fabric | PPS Ryton |
| Maximum allowable operating temperature | 375° F |
| Weight finished | 18 oz/sq. yd. |
| Filter bag nominal diameter | 5” |
| Filter bag length | 282” |

Modules are 3/16” A-36 carbon steel plate, welded and stiffened for system pressure. Hoppers have a minimum valley angle of 55°. Hopper auxiliaries consist of the following:

- 12” diameter discharge flange with manual slide gate discharge valves
- One high level detector
- Two 4” capped poke holes
- Electric hopper heaters

- Hammer anvils
- One drain connection
- One 24" diameter hinged access door with Viton seals

One inlet damper is provided for each compartment. Each damper is a 48" x 128" butterfly type which includes air cylinder, manual lockouts, four way solenoid valve, air speed control valves, and two limit switches. The inlet damper is closed only when a compartment must be isolated for personnel entry while other compartments remain on-line.

Two outlet dampers are provided for each compartment. Each damper is a 64" diameter poppet-type assembly which includes air cylinder, manual lockout, four-way solenoid valve, air speed control valves, and two limit switches. Outlet dampers must be closed for off-line bag cleaning and isolation for personnel entry when other compartments remain on-line.

One vent damper is provided for each compartment. Each damper is a 12" diameter poppet type assembly which includes an air cylinder operator. The vent damper is provided for pressure relief when removing the roof door and for natural convection ventilation.

A fabric filter compartment may be isolated for maintenance while the other seven compartments remain on-line filtering flue gas. The compartment is isolated using a local isolation switch or from the DCS. This automatically closes the compartment inlet and outlet dampers. The compartment purge air damper opens. The compartment outlet dampers are mechanically locked out by operation/maintenance personnel using a locking pin. The fabric filter roof door is then unlatched and removed using an overhead hoist. This provides access to the top of the bags.

The fabric filter bags are cleaned using a reverse pulse of compressed air. Four isolatable pulse air headers are provided per module. Each pulse header supplies air to thirteen pulse valves. Pulse valves are double diaphragm design. They are activated by opening a pilot solenoid valve. When opened, pulse air is supplied down a manifold to 20 bags. Holes in the bottom of the manifold direct pulse air into the top of the bags. The reverse pulse of air dislodges the dust from the bags. The dust falls into the hopper.

#### 4.3.6.3 $SO_2$ Removal in the Fabric Filter

Additional $SO_2$ and HF removal occurs in the fabric filter when the flue gas passes through the built up filter cake on the FF bags. The fabric filter cleaning sequence is designed to maintain maximum filter cake on the bags to improve acid gas removal in the fabric filter and minimize lime consumption. Acid gas removal is negatively affected when fabric is cleaned and then brought back on-line because the cleaned fitter bags have less of a filter cake and almost no reactive absorbent.

The fabric filter collector utilizes two operating modes of cleaning: on-line (preferred) and off-line. On-line cleaning is done when all of the inlet and outlet dampers of non-isolated compartments are open. This allows all of the compartments to be actively filtering while they are cleaning. When using this method of cleaning, the fabric filter collector will clean a predetermined number of filter bags in one compartment, and then step to the next compartment in the cleaning sequence. A memory function in the cleaning system ensures that all filter bags are cleaned only once during a cleaning cycle.

The on-line cleaning cycle is designed to operate based on pressure drop initiated cleaning, with a maximum time interval override. The pressure drop initiation maximizes the time dust is retained on the fabric for acid gas capture, compared with a straight time interval. The timer override minimizes the upsets that can occur with a rapid increase in boiler load. Cleaning frequency, if based on pressure drop, decreases at lower boiler loads, increasing the thickness of the built up filter cake. If there is a steep change increase in load, there will be a corresponding large increase in pressure drop. This can require the rapid cleaning of several compartments, to maintain the pressure drop setpoint, exposing several compartments of cloth with little or no filter cake to the flue gas. The timer override in the sequence limits the maximum filter cake that can be built-up and minimizes this effect.

The second operating mode of cleaning available is off-line cleaning. Here, the compartment outlet dampers are closed before pulsing the bags, effectively stopping gas flow through the compartment. The dust is easier to dislodge without the gas flow through the bags. There is also less reentrainment of the dust.

#### 4.3.6.4 Heavy Metal and Sulfuric Acid Mist/Sulfur Trioxide Control

The primary mechanism for heavy metal and Sulfuric Acid Mist/$SO_3$ control is condensation in the SDA and collection of the subsequent aerosol in the fabric filter. Collection is primarily dependent on fine (sub-micron) particulate collection efficiency. The WAPC Fabric Filter utilizes Ryton felt as the bag material. The dense construction of the felt provides a better filtering surface than a woven cloth bag.

#### 4.3.6.5 Ammonia Slip from Boiler

Ammonia is injected into the backpass area of the boiler for control of nitrous oxide ($NO_x$) emissions. Unreacted ammonia in the flue gas from the boiler is referred to as ammonia slip. The guaranteed maximum ammonia slip from the boiler is 40 ppm. This unreacted ammonia combines with sulfur trioxide to form ammonium bisulfate. The melting point of this material is about 300° F, so it is semi-liquid at typical flue gas temperatures. The ammonium bisulfate acts as a binding agent when mixed with the fly ash and significantly increases the adhesive properties of the ash as it cools. Ammonium bisulfate can also react with metals in the ash and adversely affect bag life.

The addition of ammonia will enhance the performance of the fabric filter up to concentrations of 40 ppm. The pressure drop across the bags' rate of increase will be lower and particulate emissions will be reduced. At between 40 and 60 ppm of ammonia addition, the ash cake weight on the bags will begin to increase because the filtercake will become sticky and difficult to remove by normal pulsing. The pressure loss across the bags will begin to increase significantly at this point, although the emission rate will probably continue to drop.

#### 4.3.6.6 Lime Slaking

The primary purpose of the Absorbent Preparation System is to provide a reactive lime slurry to the SDA's. The slurry consists of very fine calcium hydroxide ($Ca(OH)_2$) particles suspended in water. The finer the particle, the more $S0_2$/HCl it will absorb from the flue gas in the SDA.

Pebble lime (sometimes called quick lime) is supplied in self-unloading trucks and pneumatically conveyed into the storage silo. Its particle size will range from granular (<1/8") to pebble size (3/4"). Chemically, pebble or quick lime is calcium oxide (CaO). Calcium oxide is made by calcining (heating) limestone, which is calcium carbonate ($CaCO_3$).

Redundant vertical ball mill type slakers are provided to mix the pebble lime (CaO) with water and make the lime slurry $Ca(OH)_2$. Chemically the reaction is:

$$CaO + H_2O > Ca(OH)_2$$

There are four process considerations to regard: (1) The chemical reaction is “exothermic” which means it gives off heat. (2) The reaction is temperature dependent; the higher the temperature, the faster the reaction progresses. (3) A slurry that is slaked very hot produces a much finer $Ca(OH)_2$ particle and a much more reactive slurry. This improves the SDA operation. A slurry that is slaked cold is not as reactive and presents handling problems. (4) The grinding action of the Vertimill will produce a finer, more active slurry.

#### 4.3.6.7 Vertical Ball Mill Slaker Operation

The Vertimill operates at a fixed, manually adjustable flow rate. Pebble lime is fed from the Lime Storage Silo using a rotary feeder/weigh belt. The lime feed rate is manually set at the DCS. Lime drops from the feeder to the feed bowl. Water is added in the feed bowl based on a ratio of the lime feed rate. The lime water mixture then drops into the vertimill.

The vertimill reacts the pebble lime with the water to form calcium hydroxide. The chemical reaction in itself produces a fine particle size. The grinding action of the ball mill promotes the reaction by mechanically grinding the pebble lime, providing more surface area for the slaking reaction. The grinding action also reduces the size of the grits or inert materials in the pebble lime that do not slake.

The vertimill consists of a vertical chamber with a center mounted grinding ball agitator. Steel balls are charged into the chamber. The agitator circulates the balls down through the center and up the outside of the chamber. A Mill Recycle Feed Pump recirculates the lime slurry by pumping into the bottom of the vertimill. The slurry overflows the top of the mill and overflows into the Mill Separating Chamber and then back to the inlet of the Mill Recycle Feed Pump.

The large pebble lime particles from the feed bowl are drawn down into the center of the mill into the ball charge. The slaking reaction begins. The particles then pass up the outside of the vertimill chamber. The smaller lime particles float out of the mill overflow port into the settling chamber. The larger particles are drawn back into the ball charge.

The settling chamber is a cylindrical tank with a conical bottom and a center dividing plate. The Mill Recycle Pump is designed for a 1500 gpm flow rate. The mill overflow rate into the settling chamber is equal to this recirculation rate plus the pebble lime and water feed into the mill, (nominal 500+ gpm). The slurry passes down one side of the settling chamber. The majority of the flow (1500 gpm) passes out through the bottom of the chamber and into the Mill Recycle pumps. The remainder of the slurry (500 gpm) makes a 180-degree turn, passes up the other side of the dividing plate, and overflows the Separating Chamber into the Lime Slurry Transfer Tank. The momentum of the larger particles causes them to pass out the bottom of the Separating Chamber and into the recycle pump. The smaller particles make the 180-degree turn around the bottom of the dividing plate and float out of the Separating Chamber.

A scrubber assembly located on top of the separating tank prevents moist air from coming in contact with the dry feed lime by creating an airflow from the feed bowl to the separating tank, and removing moisture and dust from the airflow. This prevents premature slaking and plugging of the feed inlet.

#### 4.3.6.8 Pebble Lime and Water Quality

The Slaking System is designed for the following minimum pebble lime characteristics:

| | |
|---|---|
| Particle Size: | less than 0.75” |
| Available CaO Content: | 85% |

Lime Slaking Reactivity per ASTM Standard C-110:

| | |
|---|---|
| Slaking Temperature Rise: | 4° C/minute |
| Maximum Reaction Time: | 10 minutes |

Low CaO content will effectively derate the capacity of the slakers. If a low reactivity lime is supplied, it will slow the slaking reaction, resulting in a coarser slurry and a less reactive lime slurry.

The system is designed to use Reuse Water for the Vertimill Slaker Feed.

### 4.3.7 System Design Basis

The Dry Scrubbing System has been designed to meet the Repowering Project emission requirements while operating over a boiler range of:

- 25% to 100% MCR
- Six different fuels including:
  - Performance Coal
  - Worst Case $SO_2$ Coal
  - Worst Case $NO_x$ Coal
  - Performance Petroleum Coke
  - Worst Case $SO_2$ Petroleum Coke
  - Worst Case $NO_x$ Petroleum Coke

Tables 4-1a and 4-1b summarize parameters at the SDA inlet for maximum and minimum design load and the six fuels.

Table 4-1a SDA Inlet Parameters Coal

| **Fuel** | **Performance** | | **Worst $SO_2$** | | **Worst $NO_x$** | |
|---|---|---|---|---|---|---|
| MCR | 100% | 25% | 85% | 25% | 85% | 50% |
| % CFB $SO_2$ Removal | 85% | 85% | 85% | 85% | 85% | 85% |
| % CaO in Flyash Available | 25% | 25% | 25% | 25% | 25% | 25% |
| | | | | | | |
| Flue Gas Flow Rate | | | | | | |
| lb/hr | 2,596,548 | 1,265,418 | 2,665,212 | 1,316,268 | 2,712,942 | 1,769,280 |
| SCFM | 561,609 | 278,293 | 579,219 | 287,398 | 592,975 | 387,616 |
| ACFM | 825,946 | 373,665 | 854,046 | 385,890 | 876,596 | 523,057 |
| | | | | | | |
| Flue Gas Pressure (in Wg) | -19 | -5 | -20 | -5 | -21 | -7 |
| Flue Gas Temperature (° F) | 280 | 240 | 280 | 240 | 280 | 240 |
| | | | | | | |
| Flue Gas Composition | | | | | | |
| $O_2$ (vol% wet) | 3.2% | 9.78% | 3.2% | 9.77% | 3.2% | 4.41% |
| $SO_2$ (ppm vol wet) | 366 | 161 | 551 | 397 | 204 | 190 |
| HCl (ppm vol wet) | 122 | 122 | 122 | 122 | 122 | 122 |
| HF (lb/mmbtu) | 0.0106 | 0.0106 | 0.0106 | 0.0106 | 0.0106 | 0.0106 |
| $SO_3$ (lb/mmbtu) | 0.018 | 0.005 | 0.033 | 0.008 | 0.012 | 0.013 |
| $NH_3$ (ppm vol wet) | 15 | 40 | 15 | 40 | 15 | 40 |
| Pb (lb/mmbtu) | 2.83E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 |
| Hg (lb/mmbtu) | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 |
| Solids (gr/acf) | 2.889 | 3.315 | 3.014 | 3.513 | 1.668 | 1.632 |
| | | | | | | |
| Mass Flow Rate | | | | | | |
| $SO_2$ (lb/hr) | 2,050.2 | 447 | 3,179.4 | 1,137 | 1,207.8 | 733.8 |
| HCl (lb/hr) | 922.2 | 457.2 | 922.2 | 470.4 | 882.6 | 637.2 |
| HF (lb/hr) | 28.2 | 22.2 | 25.2 | 22.2 | 25.2 | 15.6 |
| $SO_3$ (lb/hr) | 49.2 | 10.2 | 79.2 | 17.4 | 29.4 | 19.2 |
| $NH_3$ (lb/hr) | 22.2 | 29.4 | 22.8 | 30.6 | 23.4 | 40.8 |
| Pb (lb/hr) | 7.2 | 6 | 6.6 | 6 | 6.6 | 4.2 |
| Hg (lb/hr) | 0.0453 | 0.036 | 0.0405 | 0.036 | 0.0407 | 0.0248 |
| Fly Ash (lb/hr)(1) | 20.573 | 10,668 | 22,193 | 11,670 | 12,593 | 7,352 |
| CaO (lb/hr)(2) | 5,214 | 4,866 | 5,820 | 5,370 | 3,012 | 1,758 |

Notes:

1. Not including Pb or Hg
2. Also included with Flyash

Table 4-1b SDA Inlet Parameters Petroleum Coke

| **Fuel** | **Performance** | | **Worst $SO_2$** | | **Worst $NO_x$** | |
|---|---|---|---|---|---|---|
| MCR | 100% | 25% | 100% | 25% | 100% | 50% |
| % CFB $SO_2$ | 85% | 85% | 85% | 85% | 85% | 85% |
| % CaO in Flyash Available | 25% | 25% | 25% | 25% | 25% | 25% |
| | | | | | | |
| Flue Gas Flow Rate | | | | | | |
| lb/hr | 2,630,346 | 1,296,108 | 2,675,268 | 1,316,022 | 2,699,928 | 1,545,360 |
| SCFM | 564,045 | 281,411 | 572,991 | 287,352 | 583,716 | 335,131 |
| ACFM | 831,673 | 377,852 | 844,863 | 385,829 | 862,908 | 452,233 |
| | | | | | | |
| Flue Gas Pressure (in Wg) | -20 | -5 | -20 | -5 | -21 | -7 |
| Flue Gas Temperature (° F) | 280 | 240 | 280 | 240 | 280 | 240 |
| | | | | | | |
| Flue Gas Composition | | | | | | |
| $O_2$ (vol% wet) | 3.3% | 9.82% | 3.2% | 9.77% | 3.2% | 4.49% |
| $SO_2$ (ppm vol wet) | 662 | 404 | 840 | 397 | 311 | 288 |
| HCl (ppm vol wet) | 122 | 122 | 122 | 122 | 122 | 122 |
| HF (lb/mmbtu) | 0.0106 | 0.0106 | 0.0106 | 0.0106 | 0.0106 | 0.0106 |
| $SO_3$ (lb/mmbtu) | 0.054 | 0.021 | 0.068 | 0.020 | 0.025 | 0.027 |
| $NH_3$ (ppm vol wet) | 15 | 40 | 15 | 40 | 15 | 40 |
| Pb (lb/mmbtu) | 2.83E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 | 2.8E-03 |
| Hg (lb/mmbtu) | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 | 1.7E-05 |
| Solids (gr/acf) | 2.918 | 3.553 | 3.689 | 3.513 | 1.459 | 1.482 |
| | | | | | | |
| Mass Flow Rate | | | | | | |
| $SO_2$ (lb/hr) | 3,718.2 | 1,134 | 4,794 | 1,137 | 1,809 | 961.8 |
| HCl (lb/hr) | 390 | 198 | 390 | 199.2 | 369 | 232.2 |
| HF (lb/hr) | 27.6 | 22.2 | 27.6 | 22.2 | 28.2 | 15 |
| $SO_3$ (lb/hr) | 140.4 | 43.8 | 178.2 | 43.2 | 65.4 | 37.8 |
| $NH_3$ (lb/hr) | 22.2 | 30 | 22.8 | 30.6 | 23.4 | 35.4 |
| Pb (lb/hr) | 7.2 | 6 | 7.2 | 6 | 7.2 | 3.6 |
| Hg (lb/hr) | 0.0444 | 0.0360 | 0.0445 | 0.0360 | 0.0448 | 0.0238 |
| Fly Ash (lb/hr)(1) | 20,921 | 11,562 | 26,873 | 11,670 | 10,853 | 5,768 |
| CaO (lb/hr)(2) | 7,098 | 6,462 | 8,784 | 6,486 | 3,834 | 2,040 |

Notes:

1. Not including Pb or Hg
2. Also included with Flyash

## 4.4 Balance of Plant Major System Descriptions

This section contains system descriptions of some of the major existing Balance of Plant systems which were affected by the Repowering Project. The following systems are described:

Condensing
Circulating Water
Boiler Feed
Condensate
Condensate Polishing
Main Steam
Reheat Steam
High-Pressure Extraction
Low-Pressure Extraction
480 Volt AC Power Supply
4160 Volt AC Power Supply
DC Power Supply

The enhancements and upgrades described in the sections below for each system were implemented as part of the initial design and construction for the Repowering Project.

### 4.4.1 Condensing

The existing Condensing System condenses main cycle exhaust steam and other reclaimable steam. In addition, the system serves as a collection point for cycle drains which are reclaimable as condensate. The system returns condensate to the Condensate System and also provides short-term condensate storage.

The Condensing System for each unit consists of the following major components:

- One two-pass, single shell, single pressure condenser
- Two full-capacity, vertical, wet suction, can-type condensate pumps with motors
- Suction, discharge, and condensate makeup piping and valves

The low-pressure turbine exhausts downward into the condenser shell. Exhaust steam, and other recoverable steam and condensate, is also routed to the condenser shell. The steam is condensed in the condenser shell due to cold circulating water passing through the condenser tubes.

The area in the bottom of the condenser shell serves as a hot well for condensate storage. The condenser hot well supplies condensate to the suction of the vertical can-type condensate pumps.

The condensate pumps and condensate booster pumps provide the head necessary to pump the condensate to the deaerator. A recirculation line from a point downstream of the steam packing exhauster to the main condenser is provided to maintain minimum required condensate pump flow and minimum required steam packing exhauster flow during start-up and low load operation.

The condenser hot well level must be maintained within limits to assure that water will always be available to the condensate pumps and to assure that flooding of the condenser shell will not occur. Makeup water from the sweet water and/or boiler water systems is provided to the condenser during normal and low level operation through makeup control valves. During periods when the hot well level is high, condensate from a point downstream of the steam packing exhauster is dumped to the sweet water system through dump control valves.

**Enhancements and Upgrades.** The Unit 1 and Unit 2 condensers were retubed with titanium tube bundles (original material was aluminum-brass) and the water boxes were repaired or replaced. Unit 2 condensate pumps and pump motors were restored to reliable operation. Drain manifolds for main steam, high-pressure, and hot reheat steam were inspected to confirm integrity and cleaned to remove debris.

### 4.4.2 Circulating Water

The existing Circulating Water System provides cooling water to the condenser for condensing the main turbine exhaust steam as well as cooling water to the Closed Cooling Water System and condenser exhausters. The system rejects the waste heat to the St. Johns River.

The Circulating Water System for each unit consists of the following major components:

- Two 50% capacity, vertical circulating water pumps with motors
- Two traveling screens
- Circulating water piping, valves, and expansion joints
- One pair of screen wash pumps which serve the Unit 1, Unit 2, and Unit 3 traveling screens
- Condenser vents and drains

The two half-capacity, vertical circulating water pumps supply cooling water to the condenser and to the dirty water (river water) side of the closed cooling water heat exchangers and the condenser exhauster heat exchangers. Heated water from the condenser, the closed cooling water heat exchangers, and the condenser exhausters is returned to the river through the circulating water piping.

**Enhancements and Upgrades.** Cathodic protection systems were installed. Two new circulating water pumps and motors were provided for Unit 2, and two for Unit 1. Unit 2 circulating water pump discharge piping to the condenser, and from the condenser to the discharge flume, was dewatered, cleaned, inspected, and repaired as required. The Unit 2 circulating water pump structure was repaired and refurbished, similar to repairs and refurbishment previously performed by JEA for Unit 1. Circulating Water System common intake canal was inspected to confirm integrity for continued service. New Unit 2 circulating water intake traveling screens were installed, including new traveling screens, new screen drive motors, and associated wash water piping. Base slab and walls for the Unit 1 discharge flume were repaired. Appropriate construction techniques were used to ensure the common discharge flume remained operational during reconstruction.

### 4.4.3 Boiler Feed

The existing Boiler Feed System provides for flow of feedwater from the deaerator storage tank to the economizer inlet, provides a portion of the regenerative feedwater heating, and supplies desuperheating water to the main steam and reheat steam desuperheaters.

The Boiler Feed System for each unit consists of the following major components:

- One half-capacity main steam turbine driven boiler feed pump, with variable speed fluid drive
- One half-capacity motor driven boiler feed pump, with variable speed fluid drive

- Two horizontal U-tube type feedwater heaters equipped with integral drain coolers
- Interconnecting piping and valves between the deaerator storage tank and the steam generator economizer

Feedwater from the deaerator storage tank flows to the boiler feed pumps. The boiler feed pumps supply the additional pressure head necessary to overcome the friction losses in the high-pressure feedwater heaters and piping. They also provide the pressure required at the steam generator economizer inlet (approximately 2,875 psig).

Two stages of regenerative feedwater heating are provided by high-pressure feedwater heaters of the shell and U-tube type. The heaters are arranged in a horizontal position. Feedwater flow is through the tubes, and extraction steam from the main turbine is admitted to the heater shell side.

Bypass piping is provided to individually divert feedwater flow around the high-pressure heaters if required for heater isolation. All bypass and block valves are motor operated.

The Boiler Feed System provides spray water to desuperheaters in the Steam Generator System and the Reheat Steam System.

**Enhancements and Upgrades.** The high-pressure feedwater heaters (Heaters 1 and 2) in Units 1 and 2 were replaced. New boiler feed pump recirculation control valves were provided for Unit 2. The adequacy of the existing recirculation piping to the deaerator was evaluated and partially replaced. New pump rotating elements (higher head/capacity rating) were provided for the Unit 1 and Unit 2 boiler feed pumps. The adequacy of the existing fluid drives was evaluated and upgraded. Start-up strainers were installed in the suction lines to the Unit 1 and Unit 2 boiler feed pumps. Unit 1 and Unit 2 boiler feed pump motors were replaced. Unit 2 boiler feed pump air-operated discharge check valves were replaced with tilting disk check valves similar to those on Unit 1. Unit 2 boiler feed pump start-up lube oil pumps and motors were refurbished to restore to reliable operation. Unit 2 boiler feedwater piping was inspected, flushed, hydrotested, and chemically cleaned. Selected welds were subjected to NDE to confirm integrity. Unit 2 boiler feedwater cold reheat attemperation piping was replaced, flushed, and hydrotested by Foster Wheeler. Unit 1 and Unit 2 boiler feedwater piping was extended to the new boilers by Foster Wheeler. Calibrated ASME flow nozzles in accordance with ASME PTC 6 were installed in the Unit 1 and Unit 2 feedwater piping by Foster Wheeler.

### 4.4.4 Condensate

The existing Condensate System provides a flow path for water from the Condensing System to the deaerator and raises the temperature of the condensate through regenerative feedwater heating.

The Condensate System for each unit consists of the following major components:

- Two full-capacity, horizontal, centrifugal condensate booster pumps with variable speed fluid drives
- Three horizontal, U-tube type, low-pressure feedwater heaters, equipped with integral drain coolers
- One direct contact tray-type deaerator with a horizontal cylindrical shell storage tank
- Interconnecting piping and valves between the Condensing System and the deaerator, including heater bypass piping and valves

Condensate is supplied from the Condensing System to the condensate polishing units. From the condensate polishers, the condensate flows to the steam packing exhausters. Downstream of the steam packing exhausters are branch connections for condensate recirculation to the condenser and boiler feed pump seal water. The condensate flows through the condensate flow control valve station and then to Low-Pressure (LP) Feedwater Heater 6 located horizontally in the condenser exhaust neck. Heated condensate flows to the condensate booster pumps. The low-pressure heater drains are discharged into the suction pipe of the condensate booster pumps. The condensate booster pumps add the additional head required to deliver the increased flow of heated condensate in series through LP Heaters 5 and 4. Heated condensate from LP Heater 4 flows to the deaerator (Heater 3) and then to the deaerator storage tank.

The deaerator is designed to remove dissolved oxygen from the condensate. The deaerator is the direct contact tray type, consisting of a horizontal cylindrical shell deaerating section supported on a horizontal cylindrical shell water storage tank section.

Automatic condensate bypass of the low-pressure heaters is provided by motor-operated bypass and isolation gate valves for turbine water induction prevention and heater maintenance. The heater bypass valve will open and the isolation valves will close automatically in the event of high heater water level or turbine trip.

**Enhancements and Upgrades.** Unit 1 and Unit 2 deaerator heater and storage tanks were replaced. Unit 2 bitter water (dimineralized water from the demineralizer) piping was inspected and flushed to confirm integrity and remove debris. Unit 2 condensate booster pumps and fluid drives were refurbished to restore to reliable operation. New booster pump motors were provided for Unit 1 and Unit 2. Unit 1 and Unit 2 LP Feedwater Heater 6 tube bundle was replaced. Unit 1 and Unit 2 LP Feedwater Heaters 4 and 5 were replaced. Unit 2 condensate piping and condensate recirculation piping was inspected, flushed, chemically cleaned, and hydrotested. Unit 2 condensate pump suction piping was replaced. Pumps and motors for the Unit 1 and Unit 2 feedwater heater drains were replaced. Unit 2 Feedwater Heater 6 flash chamber, hot well, and flashpot were internally inspected, refurbished, and cleaned. Cascade drain piping for the Unit 2 feedwater heaters was inspected, flushed, and chemically cleaned.

### 4.4.5 Condensate Polishing

The existing Condensate Polishing System removes suspended and dissolved solids from the condensate which may enter due to condenser tube leaks, with the cycle makeup water, or from cycle piping due to transient load operation or start-up. Removal of these solids aids in maintaining the boiler water at the specified quality, helps prevent water side attack on boiler metal, and allows proper steam purity to be maintained.

The Condensate Polishing System consists of the following major components:

- Three 50% capacity deep bed condensate polishers to provide condensate filtration and ion exchange
- Two horizontal, centrifugal type recycle pumps
- Three external regeneration vessels – one for cation regeneration and resin separation, one for anion regeneration, and one for resin mixing and storage
- Regeneration water heater
- Resin sluice and regeneration water pumps
- Acid and caustic regeneration manifolds
- Interconnecting piping and valves between the components within the system
- Local control system

The condensate polisher is located in the condensate/feedwater cycle between the condensate pump discharge and the gland condenser. The system is designed for full flow condensate polishing; i.e., the total condensate flow is passed through the system. Full flow condensate polishing is possible with two of the three 50% polisher units on-line, allowing one polisher to be off-line for resin transfer or maintenance. Resin is periodically transferred from the polishers to the cation regeneration tank for resin separation, backwash, and regeneration.

**Enhancements and Upgrades.** The Unit 2 Condensate Polishing System was entirely replaced.

### 4.4.6 Main Steam

The existing Main Steam System conveys superheated steam from the steam generator superheater outlet to the main turbine stop valves.

The Main Steam System includes the following major components:

- One main steam line
- Two branch lines to the main turbine stop valves
- Two safety relief valves
- Drain piping and valves
- Turbine seal steam piping and valves

Main steam is heated in the steam generator and flows from the superheater outlet header through the main steam line to the branch lines serving the main turbine stop valves. The main steam piping is constructed of ASTM A335 P91 chrome-moly steel.

Drain pots are provided for water removal from the main steam line. These drain pots are located at low points in horizontal runs as near as practical to the main turbine.

The Main Steam System is designed with appropriate margins for the main steam flow at the turbine generator valves-wide-open conditions.

**Enhancements and Upgrades.** Main steam piping was replaced by Foster Wheeler. Main steam piping was subjected to steam blow by Foster Wheeler to remove debris and corrosion products. A 40% capacity turbine bypass system, with control valves and motor-operated shutoff valves, was installed by Foster Wheeler for Unit 1 and Unit 2 to transport warming steam to the condenser.

### 4.4.7 Reheat Steam

The existing Reheat Steam System provides a flow path for cold reheat steam from the high-pressure turbine exhaust to the reheater inlet and for hot reheat steam from the reheater outlet to the intermediate-pressure turbine inlet.

The Reheat Steam System includes the following major components:

- One cold reheat line, with two branch lines at the turbine
- One hot reheat line, with two branch lines in the turbine building
- Cold reheat and hot reheat safety valves
- Drain piping and valves
- One reheat desuperheater with spray piping and valves

Cold reheat steam exhausts from the high-pressure turbine into two cold reheat branch lines. These branch lines connect into a single cold reheat line. A drain pot is provided near the high-pressure turbine exhaust for water removal from the cold reheat piping. The drain pot is drained to the condenser. Safety valves are provided near the reheater inlet for system overpressure protection.

Hot reheat steam is routed from the steam generator reheater outlets to the intermediate-pressure turbine inlets. Drain pots are located at a low point in a horizontal run of each hot reheat line as near as practical to the intermediate-pressure turbine. Water is removed from the drain pots by way of valves and piping to the condenser. One safety valve for the hot reheat lines is provided for system overpressure protection. The hot reheat steam piping is constructed of ASTM A335 P22 chrome-moly steel.

The Reheat Steam System is designed for reheat steam flow at the turbine generator valves-wide-open conditions.

**Enhancements and Upgrades.** Cold reheat steam piping and hot reheat steam piping were replaced by Foster Wheeler. Unit 1 and Unit 2 hot and cold reheat piping was subjected to steam blow by Foster Wheeler to remove debris and corrosion products. A 40% capacity turbine bypass system with control valves and motor-operated shutoff valves, including a cold reheat check valve, was installed by Foster Wheeler for Unit 1 and Unit 2 to transport warming steam to the condenser.

### 4.4.8 High-Pressure Extraction

The existing High-Pressure Extraction System conveys extraction steam from the high-pressure (HP) and intermediate-pressure (IP) turbine to the deaerator and the high-pressure feedwater heaters.

The High-Pressure Extraction System for each unit consists of the following major components:

- Interconnecting piping and valves between the turbine extraction connections and the component served
- Power-assisted nonreturn check valves and power-operated shutoff valves in the interconnecting piping
- Drain piping and valves

The extraction steam lines to Feedwater Heaters 1 and 2 each have in the direction of steam flow a drain pot with an automatic drain to the condenser, a power-operated gate valve, a power-assisted nonreturn check valve, and an automatic drain to the condenser.

The extraction steam line to the deaerator includes two power-assisted nonreturn check valves. The nonreturn check valves are located near the turbine and are used primarily for turbine overspeed protection. A power-operated gate valve is provided. A drain pot with an automatic drain to the condenser is provided between the IP turbine and the first nonreturn check valve. Automatic drains are also provided downstream of the nonreturn check valves.

The High-Pressure Extraction System is designed for the steam flow conditions consistent with the turbine generator valves-wide-open conditions.

**Enhancements and Upgrades.** Unit 2 extraction piping was inspected internally at dis-assembled valves and hydro tested to confirm integrity for continued service.

### 4.4.9 Low-Pressure Extraction

The existing Low-Pressure Extraction System conveys extraction steam from the low-pressure (LP) turbine to the low-pressure feedwater heaters for regenerative feedwater heating.

The Low-Pressure Extraction System for each unit consists of the following major components:

- Interconnecting piping between the turbine extraction connections and the component served
- Power-assisted nonreturn check valves and power-operated shutoff valves in the interconnecting piping
- Drain piping and valves

The extraction steam lines to Feedwater Heaters 4 and 5 each have in the direction of steam flow a drain pot with an automatic drain to the condenser, a power-operated gate valve, a nonreturn check valve, and an automatic drain to the condenser. The drains provide the capability of dumping extraction steam condensate to the condenser following a turbine trip or high feedwater heater level.

Since Feedwater Heater 6 is located in the condenser neck, the extraction steam lines to this heater do not include butterfly valves, nonreturn check valves, or drains.

The Low-Pressure Extraction System is designed for the steam flow conditions consistent with the turbine generator valves-wide-open conditions.

**Enhancements and Upgrades.** Unit 2 extraction piping was inspected internally at dis-assembled valves and hydrotested to confirm integrity for continued service.

### 4.4.10 480 Volt AC Power Supply

The existing AC Power Supply (480 V) System provides ungrounded three-phase power to plant auxiliaries requiring 480 volt three-phase power.

The AC Power Supply (480 V) System consists of the following major components:

- Secondary unit substations to distribute power to large 480 volt loads and 460 volt motors from 101 horsepower through 200 horsepower (except for special applications)
- Motor control centers to distribute power to 480 volt loads and to 460 volt motors from ¾ horsepower through 100 horsepower. (Larger horsepower loads may be on MCC's in special applications)
- 480 volt AC panelboards to distribute power to small 480 volt loads

The secondary unit substation (SUS) transformers receive three-phase power from the AC Power Supply (4160 V) System and transform it to 480 volt three-phase power. The SUS transformers supply the 480 volt three-phase power to SUS buses through a main breaker. The SUS buses are connected in pairs through a tie breaker or to a common start-up bus. The main breakers and the tie breakers make it possible for an SUS bus to be fed from one source or from two separate sources. The SUS transformers are cast-coil or oil filled.

The SUS distributes power through feeder breakers to large 460 volt motors (generally 101 through 249 horsepower), to large heating loads, and to motor control centers (MCC's). The MCC's distribute power to small 480 volt motors (generally 3/4 through 100 horsepower), to 480 volt power panels and to intermediate 480 volt loads (30 to 225 amps). The 480 volt power panels distribute power to small 480 volt loads (generally 30 amps or less).

**Enhancements and Upgrades.** Most of the SUS and MCC equipment was old and replacement parts were not readily available. Therefore, they were replaced with new equipment. The existing Unit 1 and Unit 2 AC Power Supply System 480 volt equipment was reviewed and inspected, and decommissioned circuits were removed from the equipment. New one-line drawings were created for each MCC, SUS, and distribution panel and new nameplates were installed as appropriate. Abandoned circuit breakers and starters were used to support new equipment only where approved by JEA, and after testing and refurbishing the equipment, completing equipment load calculations, and leaving 20% spares.

### 4.4.11 4160 Volt AC Power Supply

The existing AC Power Supply (4160 V) System provides a resistance grounded power source to plant auxiliaries requiring 4160 volt power.

The existing AC Power Supply (4160 V) System of each unit consists of the following major components:

- One station service transformer with two secondary windings
- One starting transformer with single secondary windings
- Neutral grounding resistors on the secondary windings of the station service and starting auxiliary transformers
- Disconnect switches between the station service transformer high voltage windings and high voltage power source
- 4160 volt, 250 MVA switchgear to distribute power to 4160 volt loads
- 4160 volt non-segregated phase bus duct from the station service and starting transformers to the 4160 volt switchgear
- Protective relaying at selected points throughout the AC Power Supply (4160 V) System

The station service transformer receives power at generator nominal voltage from the generator isolated phase bus duct. This power is transformed from generator voltage to a nominal system voltage of 4160 volts and delivered to the 4160 volt switchgear through nonsegregated phase bus duct. The 4160 volt switchgear distributes power through feeder breakers to the various 4160 volt auxiliary loads. External bus duct connections at the station service transformer are such that the system phase relationships between the auxiliary transformers are in phase.

The starting and auxiliary station service transformers receive power from switchyards through subtransmission lines. This power is transformed from substation voltage to a nominal system voltage of 4160 volts and delivered to the 4160 volt switchgear through nonsegregated phase bus duct. A crosstie is provided so that the auxiliary station service and starting transformers can be used for both units.

**Enhancements and Upgrades.** Most of the 4160 volt switchgear equipment was old and replacement parts were not readily available. Therefore, all of the 4160 volt switchgear in the Turbine Island was replaced. Two new 3-winding boiler service transformers (approximately 30 to 40 MVA each) were installed for use in powering new 4160 volt boiler loads for Unit 1 and Unit 2. Foster Wheeler designed, furnished, and installed all plant connections, all 4160 volt bus duct transformer foundations, and hardware necessary to extend the low voltage side of the new transformers to the Boiler and AQCS Area switchgear for distribution. Foster Wheeler also furnished and installed additional new AC power supply 4160 volt equipment as required to support new equipment and facilities in Foster Wheeler's scope of supply. The existing Unit 1 and Unit 2 AC power supply 4160 volt equipment was reviewed and inspected, and decommissioned circuits were removed from the equipment. New one-line drawings were created for each switchgear. All Unit 1 and Unit 2 switchgear were replaced, and all 4160 volt circuit breakers were replaced with new vacuum type circuit breakers or contactors. The Unit 1 and Unit 2 nonsegregated bus duct was inspected, cleaned, repaired, and tested, or replaced as appropriate.

### 4.4.12 DC Power Supply

The existing DC Power Supply System provides a reliable source of power for critical control and power functions during normal and emergency plant operating conditions.

The DC Power Supply System consists of the following major components:

- Batteries, 60 cell, 125 volt DC lead-acid – one for Unit 1 and one for Unit 2 to serve 125 volt DC loads, and one for Unit 1 turbine emergency oil pumps
- Two full-capacity (125 volt DC) battery chargers per unit
- DC panelboards to distribute 125 volt DC power to DC loads

Under normal operating conditions, one of the battery chargers supplies nongrounded DC power to the DC loads. The second battery charger serves as a standby spare. The battery chargers receive 480 volt, three-phase, AC power from the AC Power Supply (480 V) System and continuously float charge the unit batteries, while simultaneously supplying power to the DC loads.

Under abnormal or emergency conditions, when power from the AC Power Supply (480 V) System is unavailable, the unit batteries supply DC power to the DC Power Supply System loads. Battery only operation of the DC loads can be maintained for at least six hours. Recharging of discharged batteries occurs whenever 480 volt power becomes available from the AC Power System.

**Enhancements and Upgrades.** The existing Unit 2 DC power supply equipment was replaced, and new one-line drawings were created for each DC system and distribution panel. A tie connection circuit was installed between Unit 2 and Unit 3 plant DC Power Supply Systems. The system was connected with cable and two breakers or fused disconnect switches, 300 amperes or larger. Abandoned circuit breakers and starters were used to support new equipment only where approved by JEA, and after testing and refurbishing the equipment, completing equipment load calculations, and leaving 20% spares.

## 4.5 Fuel Handling System (Coal, Petroleum Coke, and Limestone)

The function of the Fuel Handling System is to receive coal, petroleum coke, and limestone from "Panamax" vessels and to convey it to stockout and storage areas. From there, coal and petroleum coke are reclaimed and conveyed to the in-plant fuel silos; limestone is reclaimed and conveyed to the Limestone Preparation System.

Major components of the Fuel Handling System are noted below:

- Continuous Ship Unloader
- Belt Conveyors
- Domes

- Radial Stacker/Reclaimers
- Traveling Trippers
- Belt Feeders
- Belt Scales
- Magnetic Separators
- Metal Detectors
- Gates
- Chutework
- Conveyor Support Structures
- Dust Suppression Systems
- Dust Collection Systems
- Screw Conveyors
- Vacuum Cleaning Systems
- Hoppers
- Telescopic Chute

Fuel Handling System layout drawings are contained in Appendix 4. The physical layout of the fuel handling system is shown on the Site Arrangement drawing in Appendix 2.

### 4.5.1 Receiving System

Coal, petroleum coke, and limestone are received at the Northside river terminal. Coal and petroleum coke are delivered in 60,000 ton capacity vessels and limestone in 40,000 ton vessels. The coal and petroleum coke vessels are unloaded by a continuous bucket type ship unloader rated at 1,666 tons per hour (tph) for coal and 1,500 (tph) for petroleum coke. The limestone is unloaded by self-unloading vessels at a rate of 2,800 tph. The new dock provides support for the new unloading system.

The new ship unloader delivers the material to the new Dock Conveyor BC-1 rated at 1,666 tph for coal, 1,500 tph for petroleum coke, and 2,800 tph for limestone.

Dock Conveyor BC-1 feeds material to Conveyor BC-2 at Transfer Building 1. Conveyor BC-2 delivers the material to Conveyor BC-3 at Transfer Building 2. Conveyor BC-2 is provided with a belt scale.

Conveyor BC-3 feeds material to Conveyor BC-4 at Transfer Building 3. Conveyor BC-4 is fitted with a sampling system. Conveyor BC-4 delivers the material to Conveyor BC-5 at Transfer Building 4. Conveyor BC-5 feeds material to either Conveyor BC-6 or to Limestone Conveyor L-1 via a diverter gate at Transfer Building 5.

Limestone Conveyor L-1 is fitted with a telescopic chute and is capable of stocking out limestone in a 50,000 ton conical pile. A total storage pile of 80,000 tons can be created by mobile equipment. The limestone conveyor is rated at 2,800 tph. In addition, provisions have been made for a future diverter gate that is designed to allow the loading of trucks. This will give the potential capability to truck deliver the received materials to the St. Johns River Power Park (SJRPP) plant. Three dozer traps are provided at the limestone storage pile for reclaim. The dozer traps feed Reclaim Limestone Conveyors L-2, L-3, and L-4, respectively. Each reclaim limestone conveyor is fitted with a belt scale and magnetic separator. Each reclaim limestone conveyor is rated 50 tph and feeds the limestone preparation system.

Conveyor BC-6 delivers material to either Stacker/Reclaimer “A,” Conveyor BC-7, or to a bypass system for delivery directly to the plant. This equipment is located in Dome “A.” Conveyor BC-7 delivers the material to either Stacker/Reclaimer “B” or to a bypass system for delivery directly to the plant. This equipment is located in Dome "B." Each dome provides covered storage for approximately 72,000 tons of coal at 50 pcf and a 38° angle of repose, or 65,000 tons of petroleum coke at 45 pcf and a 38° angle of repose. Each dome is fitted with a radial stacker/reclaimer.

### 4.5.2 Reclaim System

The reclaim system is comprised of all equipment and components required to transfer fuel from the domes to the fuel silos for each boiler. The reclaim system for the Northside Plant is redundant. Each storage facility can provide sufficient reclaim rate for the two operating units. With two storage domes, the blending of coal and petroleum coke can be accomplished.

Stacker/Reclaimer "A" reclaims the stored material to Reclaim Conveyor BC-9 via Belt Feeder BF-4. Dome "A" includes an emergency reclaim hopper. This emergency reclaim hopper can feed stored material to Reclaim Conveyor BC-9 via a cutoff gate and Belt Feeder BF-6. Conveyor BC-9 delivers material to either Conveyor BC-10 or BC-11 at Transfer Building 6. The reclaim structure includes a sump pump system with piping.

Stacker/Reclaimer "B" reclaims the stored material to Reclaim Conveyor BC-8 via Belt Feeder BF-3. Dome "B" includes an emergency reclaim hopper. This emergency reclaim hopper can feed stored material to Reclaim Conveyor BC-8 via a cutoff gate and Belt Feeder BF-5. Conveyor BC-8 delivers material to either Conveyor BC-10 or BC-11 at Transfer Building 6. Conveyor BC-8 is fitted with a belt scale. The reclaim structure includes a sump pump system with piping.

Each reclaim system can deliver coal or petroleum coke at a rate of up to 600 tph.

Conveyors BC-10 and BC-11 deliver the material to a surge bin located in the Crusher Building. Conveyors BC-10 and BC-11 are each fitted with a magnetic separator and belt scale.

The surge bin includes a divider plate. The divider plate provides for a capacity of 100 tons of 45 pcf material in each half of the bin. The surge bin has two outlets and is fitted with a cutoff gate for each outlet. Each gate delivers material to a belt feeder rated at 600 tph. Each belt feeder delivers material to a 600 tph crusher. One crusher feeds material to Conveyor BC-12, and one crusher feeds material to Conveyor BC-13. The crushers and motors for the crushers were supplied by Foster Wheeler.

Conveyors BC-12 and BC-13 deliver fuel to Conveyors BC-14 and BC-15, respectively. These conveyors are rated at 600 tph each. Conveyors BC-12 and BC-13 are fitted with an "As-Fired" Sampling System and metal detector. Conveyors BC-14 and BC-15 are fitted with a traveling tripper delivering fuel to the in-plant silos. The trippers are complete with rails and silo slot seals.

### 4.5.3 Common Equipment

Dust suppression systems are provided at all material transfer points. The systems are of the foam type and directly control dust emissions at all transfer areas except the Crusher Building and the area adjacent to and above the in-plant storage silos, which have dust collectors. Reuse water (see Section 3.8) is used for the foam type dust suppression system.

Dust collection systems collect and return the dust to the surge bins or downstream of the collection points, in the case of the collection points in the Crusher Building. The dust collected in the in-plant storage silo area is returned to one of two in-plant silos.

The Transfer Buildings and Crusher Building are totally enclosed and ventilated.

The control rooms and electrical equipment rooms are provided with HVAC.

Vacuum cleaning systems (galvanized piping and vacuum tools) and washdown systems are provided at the following locations:

Washdown Systems (reuse water): all buildings and conveyors
Vacuum Systems (connection to mobile vacuum truck): all buildings and conveyors

Lighting systems are provided for all conveyors and enclosed areas, including area lighting for the handling systems at the Dock.

The Fuel Handling System is provided with Fire Protection Systems for the reclaim conveyor system from the storage domes to the tripper gallery, including the Crusher Building, Plant Transfer Building, and tripper gallery.

The Control System controls the Fuel Handling System and is provided with remote control for belt conveyors and associated equipment and necessary interlock control for the conveyors and machines (ship unloader and stacker/reclaimers).

The electrical equipment rooms house the Motor Control Center and consist of starters, transformers (as required), breakers, and switchgear (as required).

## 4.6 Ash Handling System

The ash handling system transports bed ash from the outlets of the stripper coolers to the bed ash silos. It also transports fly ash from the economizer and air heater hoppers as well as the baghouse hoppers, to the fly ash silos. Two sets of ash handling systems and associated equipment are provided, one for Unit 1 and another for Unit 2. The bed ash mechanical conveying system and fly ash vacuum conveying system in-turn consist of two fully independent parallel lines. Normally any one line is in operation and other is an installed spare; however, in an emergency upset condition both lines can be operated simultaneously. (See the Ash Handling System Piping and Instrument Diagrams in Appendix 1 for reference.)

### 4.6.1 Bed Ash Handling System

The bed ash handling system consists of mechanical conveying systems from the stripper coolers (four per unit) to an intermediate surge hopper (one per unit), and dilute phase pressure pneumatic conveying systems from the surge hopper to the ash silos. The dilute phase pressure pneumatic conveying system consists of one 100% line for each unit and one common spare 100% line for both units. Normally one designated line of each unit is in operation. The spare line can be used either when the normal designated line of any unit fails or during emergency upset condition of any one of the units. The spare line can be run simultaneously in parallel with the normal operating line of the upset unit. The pneumatic conveying systems are provided with automatic valves for interconnection allowing ash from either unit to be conveyed to respective silos of either unit.

#### 4.6.1.1 Bed Ash Mechanical Conveying System

The bed ash mechanical conveying system consists of drag type conveyors designed to operate at variable speeds.

The bed ash from the four stripper coolers enters the bed ash handling system via variable speed drive rotary air-lock feeders. The ash cooler discharge conveyors collect the material from the rotary air-lock feeders and discharge it onto either of the two gathering conveyors via automatically operated diverter valves. The gathering conveyors in-turn discharge the ash into the surge hopper through clinker grinders. The diverter valves are designed such that each can divert the material to either one line during normal condition or to both lines equally (i.e. gate in center position) during upset conditions. The surge hopper is of rectangular shape with four discharge hoppers. It is furnished with a bin vent filter including exhaust fan, a combination vacuum/pressure relief/access device, and a high level switch. The discharge hoppers are furnished with electric vibrators that are used as necessary to facilitate easy flow.

#### 4.6.1.2 Bed Ash Pneumatic Conveying System

The bed ash pneumatic conveying system consists of dilute phase pressure systems. Each line is designed to transport ash from the surge hopper to either of the two bed ash silos at a continuous rate of 43 tph, per line. Each bed ash silo is furnished with a bin vent filter, combination vacuum/pressure relief devices, high level switches, and an ultrasonic level indicator.

The bed ash from the surge hopper is fed to the pressure system through an air-lock valve/pressure tank. An air operated valve is furnished at the outlet of each discharge hopper to feed an air-lock/pressure tank alternately, i.e. one is being filled from one discharge hopper while the other is being emptied from the other discharge hopper, and to isolate the air-lock/pressure tanks when the pressure system is not operating. The system is designed such that the four discharge hoppers are emptied evenly.

There are three 100% pressure blowers; one each designated for Unit 1 and Unit 2 and one common spare. All blowers are interconnected with automatic valves.

### 4.6.2 Fly Ash Handling System

The fly ash handling system consists of a vacuum conveying system for air heater and economizer hoppers and for AQCS baghouse hoppers.

#### 4.6.2.1 Fly Ash Vacuum Conveying System

This system removes fly ash from air-heater hoppers (ten per unit), economizer hoppers (four per unit) and AQCS baghouse hoppers (eight per unit) automatically and sequentially, and pneumatically transports the ash to either of the fly ash silos at a net effective capacity of 45 tph, per line. The net capacity takes into account the non-conveying time for branch/hopper sequencing, line purging, time delays, etc. The fly ash from the airheater and economizer hoppers is conveyed directly to the ash silos. However, fly ash from the baghouse is conveyed to the AQCS recycle storage bin or to the fly ash silos, depending upon ash levels in the AQCS recycle storage bin. Each ash silo is furnished with two filter/separators, a combination vacuum/pressure relief device, high level switches, and an ultrasonic level indicator.

A modified filter/separator (bin-vent type) is provided on top of the AQCS recycle storage bin (one per unit) to separate most of the baghouse fly ash only. The exhaust from the filter/separator is connected to either of the two main conveying lines to the fly ash silos to separate the remaining fly ash. The AQCS recycle storage bin is furnished with low and high level switches. The fly ash from the baghouse only is conveyed to the AQCS recycle storage bin if the ash level is at low level, or it is conveyed directly to the fly ash silos, bypassing the AQCS recycle storage bin, if the ash level is at high level.

One collecting line is provided underneath each row of air heater, economizer and baghouse hoppers, and two main conveying lines are provided to the fly ash silos. The hopper collecting lines are valved to both conveying lines such that either of the lines can be operable independently during normal conditions, and both lines can be operated during upset conditions. Each conveying line has its own filter/separator.

Four 100% vacuum exhausters are provided (two per unit); one each designated for each silo filter separator. All exhausters are interconnected with automatic valves.

# 5.0 CAPITAL COSTS

The capital costs for the Repowering Project are summarized in Table 5-1, Summary Capital Costs, on the following page. Note that the costs for Unit 2 and half of the Common Facilities are broken out and listed separately, since DOE participation was only in the Unit 2 and Common Facilities portion of the project. The other capital costs for repowering Unit 1 and the other half of the Common Facilities are also listed, and the total capital cost for repowering Unit 1 and Unit 2, including all Common Facilities, is indicated for reference.

The column titled 1999 Baseline Amount summarizes the estimated costs at the time the project cost estimate was baselined in October 1999. The second column summarizes expenditures through July 31, 2002. Note that the effects of the DOE cost sharing in the Repowering Project are not included in Table 5-1.

Table 5-1 Summary Capital Costs

| | Description | 1999 Baseline Amount | Expended To Date |
|---|---|---|---|
| | | | |
| **Plant Unit 2:** | | | |
| **DOE Phase** | **1 Design** | | |
| Task | ...11, Project Mgmt & Support | $5,324,288 | $3,086,412 |
| Task | ...12, Permitting | $2,677,500 | $2,332,225 |
| Task | ...13, Preliminary Design | $1,794,796 | $2,175,695 |
| Task | ...14, Engineering/Detail | $18,519,051 | $23,243,907 |
| Task | ...15, Fuels Selection Study | $105,000 | $0 |
| Task | ...16, Test Plan | $25,000 | $0 |
| **DOE Phase** | **1 Design Total** | **$28,445,635** | **$30,838,239** |
| | | | |
| **DOE Phase** | **2 Construction** | | |
| Task | ...21, Project Mgmt & Support | $8,822,526 | $5,826,511 |
| Task | ...22, Environmental Monitoring | $140,000 | $29,871 |
| Task | ...23, Boiler Equip/AQCS | $148,299,458 | $118,936,722 |
| Task | ...24, Balance of Plant Equip. | $41,148,664 | $35,070,257 |
| Task | ...26, Turbine/Generator | $14,735,262 | $15,588,734 |
| **DOE Phase** | **2 Construction Total** | **$213,145,910** | **$175,452,095** |
| | | | |
| **DOE Phase** | **3 Operations** | **Not Included** | **Not Included** |
| | | | |
| | **Plant Unit 2 Total** | **$241,591,545** | **$206,290,334** |
| | | | |
| **Plant Unit Half of Common:** | | | |
| **DOE Phase** | **1 Design** | | |
| Task | ...14, Engineering/Detail Design | $3,317,024 | $2,912,005 |
| **DOE Phase** | **1 Design Total** | **$3,317,024** | **$2,912,005** |
| | | | |
| **DOE Phase** | **2 Construction** | | |
| Task | ...21, Project Mgmt & Support | $2,173,795 | $19,707,842 |
| Task | ...22, Environmental Monitoring | $0 | $104,562 |
| Task | ...23, Boiler Equip/AQCS | $7,975,354 | $9,141,358 |
| Task | ...24, Balance of Plant Equipment | $15,872,864 | $29,007,119 |
| Task | ...25, Fuel Handling Equipment | $57,947,907 | $52,974,594 |
| **DOE Phase** | **2 Construction & Start-up Total** | **$83,969,919** | **$110,935,474** |
| | | | |
| | **Plant Unit Half of Common Total** | **$87,286,942** | **$113,847,479** |
| | | | |
| Total Capital Costs – Unit 2 Plus Half of Common | | **$328,878,487** | **$320,137,813** |
| | | | |
| | **Plant Unit 1** | **$216,064,524** | **$198,695,758** |
| | **Plant Unit Common (Other Half)** | **$87,286,942** | **$113,847,479** |
| | | | |
| | **PROJECT TOTAL CAPITAL COSTS** | **$632,229,954** | **$632,681,049** |

# 6.0 OPERATING COSTS

The projected non-fuel operating and maintenance costs, in 2002 dollars, associated with the repowered Unit 1 and Unit 2 are as follows:

Fixed O & M: $7.07/kw-yr
Variable O & M: $1.74/mwh

The operating and maintenance costs will be documented and confirmed during the two year demonstration period.